UNITIL ENERGY SYSTEMS, INC.
DE 21-030
PETITION FOR RATE INCREASE

TABLE OF CONTENTS

Unitil

April 2, 2021

BY E-MAIL

Debra A. Howland
Executive Director and Secretary
New Hampshire Public Utilities Commission
21 S. Fruit St, Suite 10
Concord, N.H. 03301-2429

Re: DE 21-030 Unitil Energy Systems, Inc. - Filing of Rate Schedules

Dear Director Howland:

Pursuant to N.H. Admin. Rules Puc 1600 *et seq.*, Unitil Energy Systems, Inc. ("UES" or the "Company") hereby submits to the New Hampshire Public Utilities Commission ("the Commission") its filing in support of its request for a rate increase. Pursuant to the Executive Director's letter dated March 17, 2020 suspending all Commission rules requiring the filing of paper copies, UES is submitting this filing in electronic form only. The Company's electronic filing complies with Puc 203.03. UES will retain an original copy of the filing, and is prepared to provide paper copies at the Commission's request.

The change in permanent rates proposed for effect with service rendered on and after May 2, 2021 would increase UES's total annual revenues by $11,992,392, which represents an increase of 4.4 percent above present rates. UES is also requesting implementation of temporary rates for service rendered on and after June 1, 2021, and until a final order on permanent rates is issued. The requested temporary rates will produce an increase in annual revenues of $5,812,761, or a 2.7 percent increase above present rates.

In addition to this cover letter, the enclosed filing consists of proposed tariffs, prefiled testimony and supporting schedules, and rate case materials as required by Puc 1604.01(a).

Due to restrictions related to the Covid-19 pandemic, including the precautionary quarantining of Company personnel, UES is unable to provide a signed and notarized attestation with this filing as required by Puc 1604.04. UES hereby requests a temporary waiver of Puc 1604.04 until such time that the Company is able provide a signed and notarized attestation for inclusion in the filing.

UES respectfully requests that the Commission issue an order of notice and schedule a prehearing conference upon receipt of this filing.

Thank you for your attention to this matter. Please do not hesitate to contact me directly if you have any questions or concerns.

Sincerely,

Patrick H. Taylor

cc: Donald M. Kreis, Consumer Advocate

THE STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

DE 21-030

UNITIL ENERGY SYSTEMS, INC.

MOTION FOR PROTECTIVE ORDER AND CONFIDENTIAL TREATMENT

NOW COMES Unitil Energy Systems, Inc. ("UES" or the "Company") and, pursuant to NH RSA 91-A:5, IV and N.H. Code of Administrative Rules ("N.H. Admin. Rules") Puc 203.08, respectfully moves the New Hampshire Public Utilities Commission ("Commission") to issue a protective order which accords confidential treatment to the following information contained in documents filed with the Company's Petition for Rate Adjustments: (a) Confidential Schedules TRD-9 and TRD-10 to the Direct Testimony of Todd Diggins, Confidential for the most recent credit reports for Unitil Corporation and its subsidiaries (including UES) published by S&P and Moody's; and (b) Certain Company Officers' Compensation contained in the Volume of Supplemental Filing Requirements pursuant to N.H. Code of Administrative Rules Puc 1604.01(a)(14). UES has filed this information with the Commission and submitted it to the Office of Consumer Advocate with the understanding it will be maintained as confidential until the Commission rules on the within Motion.

In support of this Motion, UES states as follows:

I. Standard of Review

1. In determining whether confidential, commercial or financial information within the meaning of RSA 91-A:5, IV is exempt from public disclosure, the Commission applies a

three-step balancing test to determine whether a document, or the information contained within it, falls within the scope of RSA 91-A:5, IV. *Northern Utilities, Inc.*, DG 17-070, Order No. 26,129 at 15 (May 2, 2018) (*citing Liberty Utilities (EnergyNorth) Natural Gas Corp.*, Order No. 26,109 at 23 (March 5, 2018)). First, the Commission inquires whether the information involves a privacy interest and then asks if there is a public interest in disclosure. *Id.* Then the Commission balances those competing interests and decides whether disclosure is appropriate. *Id.* When the information involves a privacy interest, disclosure should inform the public of the conduct and activities of its government; if the information does not serve that purpose, disclosure is not warranted. *Id*.

II. Confidential Schedules TRD-9 and TRD-10

2. Confidential Schedules TRD-9 and TRD-10 are exempt from public disclosure under RSA 91-A, as they constitute proprietary and copyrighted information and analyses prepared and provided by ratings agencies that have value to such agencies in that they are provided only on a paid subscription basis and are not otherwise made publicly available.

3. The ratings reports prepared and issued by Moody's and S&P constitute proprietary and confidential commercial and financial information, the value of which will be impaired if released publicly. While the overall credit rating for Unitil Corporation and UES may be public, the underlying analyses supporting the ratings are not. These reports are made available to subscribers who pay a fee to access the reports and other information; they are not made publicly available. As such, the reports are proprietary and have significant value to the ratings agencies. Were the Commission to disclose the reports publicly, parties that would otherwise have to pay a fee to the ratings agencies to receive the reports would instead have free and unrestricted access to them. Such disclosure would render the reports

essentially valueless to the agencies. The ratings agencies have a clear privacy interest in these reports that warrants confidential protection.

4. The Moody's and S&P ratings reports are provided to UES and its parent and affiliate companies with the expectation that they will not be shared publicly. UES does not have the permission or discretion to disclose or disseminate them publicly, and unrestricted disclosure of the reports would constitute an unnecessary infringement upon the ratings agencies' privacy interest.

5. In evaluating an identical request for confidential treatment by the Company's affiliate, Northern Utilities, Inc. ("Northern"), the Commission determined that while the public had an interest in the content of the credit reports, that interest was not as weighty as Northern's interest in nondisclosure. *Northern Utilities, Inc.*, DG 20-078, Order No. 26,385 at 11 (July 28, 2020). The Commission explained:

> We are cognizant that the analyses and related documents are copyright protected and were provided to the Company without authority to share the information publicly. Consequently, public release of the analyses could harm the Company's ability to obtain this type of information in the future, because it could violate the terms of its agreement with the publishers and would harm the competitive interests of the publishers of the copyrighted materials if such information were provided to the public for free. Those factors make the interest in nondisclosure more substantial.

Id. The Commission should reach the same conclusion in this case. Disclosure of the reports would not provide the public with information about the conduct or activities of the Commission or other parts of the New Hampshire State or local government. Accordingly, disclosure is not warranted.

6. The Commission did conclude that the credit ratings contained in the S&P and Moody's reports are not entitled to confidential treatment. The Company does not dispute this conclusion. UES has an issuer rating of BBB+ from S&P and an issuer rating of Baa1

from Moody's. The S&P credit rating is determined based on Unitil Corporation's entire suite of subsidiaries, whereas the Moody's credit rating is specific to UES.

III. Company Officers' Compensation

7. In accordance with Puc 1604.01(a)(14), UES has submitted documents containing officer compensation and benefit information. The compensation of UES's officers (the Company's President and Senior Vice Presidents) who are or were also officers of UES's parent, Unitil Corporation, is public information which is annually disclosed in the Unitil Corporation's Proxy Statement filed with the federal Securities and Exchange Commission. The Company does not seek to protect this information from disclosure. The compensation of the remaining officers (the Company's Controller, Treasurer, three Vice-Presidents and Secretary), however, who are not officers of the parent, has not been previously disclosed or made publicly available. Public disclosure of the compensation and benefit information for these employees could harm UES's ability to negotiate the terms of employment for its current and future employees. Moreover, allowing the Company's competitors access to such information could allow competitors an unfair advantage in competing to retain similar management and executive employees.

8. The above-described information meets the Commission's three-part test. The compensation information is clearly confidential, commercial or financial, and disclosure of it would pose harm and constitute an invasion of privacy. The Commission protected substantively similar information provided in accordance with Puc 1604.01(a)(14) in Northern's most recent rate case, DG 17-070. In that case, the Commission "protect[ed] the information regarding the compensation of Northern's officers, who are not officers of Unitil, from public disclosure, because disclosure could harm Northern's ability to attract qualified

personnel." *Northern Utilities, Inc.*, DG 17-070, Order No. 26,129 at 15-16 (May 2, 2018). The Commission also noted that the information was not previously disclosed or publicly available. Though the Commission noted that the public has "some" interest in disclosure of this information, it found that the privacy interests in non-disclosure outweighed the public's interest in disclosure. *Id*. at 16. The Commission should reach the same conclusion in this case.

IV. Conclusion

9. UES is providing the confidential information described herein directly to the Office of Consumer Advocate ("OCA"), as required by RSA 363:28,VI. Provision of these materials to the OCA offers assurance to the public that this information will be subject to investigation, discovery and analysis by that office, as well as by the Staff of the Commission, and that the results of such review will be provided to the Commission for its consideration.

10. UES requests that the Commission issue an order protecting the above-described information from public disclosure and prohibiting copying, duplication, dissemination or disclosure of it in any form. UES requests that the protective order also extend to any discovery, testimony, argument or briefing relative to the confidential information.

WHEREFORE, UES respectfully requests that the Commission:

A. Issue an appropriate order that exempts from public disclosure and otherwise protects as requested above the confidentiality of the above-described information designated confidential submitted herewith; and

B. Grant such further relief as may be just and appropriate.

Respectfully submitted

UNITIL ENERGY SYSTEMS, INC.

By its Attorney:

Dated: April 2, 2021

Patrick H. Taylor
Senior Counsel
Unitil Service Corp.
6 Liberty Lane West
Hampton, NH 03842-1720
Telephone: 603-773-6544
E-mail: taylorp@unitil.com

Certificate of Service

I hereby certify that on April 2, 2020, a copy of the foregoing Motion was electronically served upon the Office of Consumer Advocate.

Patrick H. Taylor

THE STATE OF NEW HAMPSHIRE

BEFORE THE

PUBLIC UTILITIES COMMISSION

DE 21-030

UNITIL ENERGY SYSTEMS, INC.

PETITION OF UNITIL ENERGY SYSTEMS, INC.

NOW COMES Unitil Energy Systems, Inc. ("UES" or "the Company") and, pursuant to NH RSAs 378:7, 378:27, 378:28 and 378:29, respectfully petitions the New Hampshire Public Utilities Commission ("the Commission") for authority to: (1) implement new permanent rates beginning May 2, 2021, for electric service at the levels set forth in its proposed revised tariff filed with this Petition; (2) replace certain pages of UES's current tariff, NHPUC No. 3, with proposed revised tariff pages; (3) implement a multi-year Rate Plan with three annual step adjustments for certain non-revenue producing capital additions; (4) implement a revenue decoupling mechanism, which the Company has proposed in compliance with Commission Order No. 25,932; (5) implement a Grid Modernization plan that includes a group of foundational grid modernization projects; (6) implement a suite of time of use ("TOU") rate offerings, an electric vehicle infrastructure development program, and a Marketing, Communications, and Education Plan to engage with customers about the TOU rates and electric vehicle program offerings; (7) implement an Arrearage Management Program and (8) if the Commission suspends the effective date of UES's permanent rates, implement temporary rates beginning June 1, 2021 for electric service at rate levels set forth in Supplement No. 2 to NHPUC No. 3. In support of this Petition, UES states as follows:

A. RATE INCREASE AND REVISED TARIFF

1. On March 1, 2021, pursuant to NH RSA 378:3 and New Hampshire Code of Administrative Rules, Puc 1604.05, UES filed a Notice of Intent to File Rate Schedules with the Commission.

2. UES is filing with this Petition revisions to its Tariff NHPUC No. 3 ("the Permanent Rates Tariff"). This Tariff has a proposed effective date of May 2, 2021 and is intended to produce a permanent increase in annual revenues of $11,992,392, which represents an increase of 4.4 percent in total revenues above present rates after accounting for changes to other reconciling mechanisms. This permanent rate increase results in an overall rate of return of 7.88 percent which is less than the Company's last allowed rate of return of 8.34 percent. *Unitil Energy Systems, Inc.*, DE 16-834, Order No. 26,007 at 9 (April 20, 2017). The overall rate of return of 7.88 percent includes a requested Return on Equity of 10.00 percent, and a proposed capital structure consisting of 52.91% common equity, 0.10% preferred stock equity, 46.99% long-term debt, and 0.00% short-term debt.

3. Pursuant to NH RSA 378:8 and N.H. Admin. Rule Puc 1600 *et seq.*, UES has filed direct testimony and exhibits in support of the Permanent Rates Tariff and such supplementary information required by the Commission, all of which is incorporated herein by reference.

B. RATE PLAN WITH STEP ADJUSTMENTS

4. UES requests permission to implement a multi-year Rate Plan with three annual step adjustments to recover the revenue requirement associated with certain non-revenue producing capital additions to rate base, including but not limited to planned Grid Modernization investments. These projects are necessary in order to maintain UES's ability to provide safe and reliable electric service to its customers. Under the proposed Rate Plan, it is anticipated that an initial step adjustment will be implemented on the effective date of permanent rates. Thereafter, a second capital project step adjustment will be implemented on April 1, 2023, and a third capital project step adjustment will be implemented on April 1, 2024.

5. The Commission has previously authorized UES to implement a similar series of step adjustments. *See Unitil Energy Systems, Inc.*, DE 16-834, Order No. 26,007 at 18 (April 20, 2017); *Unitil Energy Systems, Inc.*, DE 10-055, Order No. 25, 214 (April 26, 2011). In support of its request for a long-term Rate Plan, UES has filed the direct testimony of Robert Hevert and the joint direct testimony of Christopher Goulding and Daniel Nawazelski.

C. REVENUE DECOUPLING

6. In DE 15-137, the Energy Efficiency Resource Standard ("EERS") docket, the Commission directed UES and other New Hampshire utilities to "seek approval of a decoupling or other lost-revenue recovery mechanism as an alternate to the [Lost Revenue Adjustment Mechanism] in their first distribution rate cases after the first EERS triennium, if not before." *Energy Efficiency Resource Standard*, DE 15-137, Order No. 25,932 at 60 (August 2, 2016). UES filed its last rate case prior to the issuance of Order

No. 25,932 and as such this is the Company's first opportunity to propose a decoupling mechanism since the Commission issued Order 25,932.

7. In compliance with the Commission's directive, UES proposes a full Revenue Decoupling Mechanism ("RDM") that reconciles monthly actual and authorized revenues per customer by rate class. UES proposes that the authorized revenues per customer be adjusted annually to reflect the three step increases on April 1, 2022, April 1, 2023, and April 1, 2024. The proposed RDM will be applicable to all rate classes, except the lighting and proposed electric vehicle rate classes discussed below, and will comprise a two-step process: first, the Company will record monthly variances between actual and authorized revenues per customer for each rate class, then aggregate the monthly variances over the twelve-month period April through March; second, the Company will file the applicable RDM adjustment factor on June 1. The proposed RDM is described at length and supported by the direct testimony of Timothy Lyons of ScottMadden, Inc.

D. GRID MODERNIZATION

8. UES is proposing a group of foundational grid modernization projects to be included within its capital spending plan. "Foundational" projects are required to achieve desired grid modernization outcomes and core functionality. The Company's proposed Grid Modernization Plan covers a span of ten years and is described in and supported by the direct testimony of Kevin Sprague.

E. ELECTRIC VEHICLE AND TIME OF USE RATES

9. UES is proposing a suite of TOU rate offerings, an electric vehicle infrastructure development program ("EV Program"), and a Marketing, Communications, and Education Plan to increase customer awareness of electric vehicles ("EVs") and

engage with customers about the Company's proposed TOU rates and EV Program offerings. These initiatives are intended to enable adoption of distributed energy resources, transportation electrification, and individualized energy management to reduce carbon emissions from the electricity sector while providing savings for UES customers.

10. The Company's proposed TOU rates include: (1) a domestic "whole-house" TOU (TOU-D); (2) a domestic EV TOU (TOU-EV-D); (3) a small general service EV TOU (TOU-EV-G2); and (4) a large general service EV TOU (TOU-EV-G1). The development of these rates was informed by the Commission's findings in Order 26,394 that resulted from IR 20-004, *Investigation of Electric Vehicle Rate Design Standards, Electric Vehicle Time of Day Rates for Residential and Commercial Customers*, and the ongoing EV TOU proceeding DE 20-170, *Electric Vehicle Time of Use Rates*.

11. The proposed EV Program contains two initiatives: (1) a behind-the-meter partnership program to incentivize residential customers to procure and install smart Level 2 electric vehicle supply equipment for charging at their homes, and (2) a public "make-ready" EV infrastructure program to expand the availability of charging stations in New Hampshire. The Marketing, Communications, and Education Plan consists of two parts: (1) a Consumer EV Education Campaign, which will increase awareness of and inform the Company's customers about the benefits of EVs, options for home and public charging, and the proposed EV TOU rates; and (2) a Consumer EV Marketing and Promotion Program that will focus on creating experiential learning opportunities for customers, partnerships with EV dealerships, and partnerships and incentives/rebates with behind-the-meter EVSE vendors.

12. UES has submitted the joint direct testimony of Cindy Carroll, Carleton Simpson, and Carol Valianti in support of its proposed TOU rates, EV Program, and Marketing, Communications, and Education Plan.

F. ARREARAGE MANAGEMENT PROGRAM

13. UES is also proposing an Arrearage Management Program ("AMP") for residential financial hardship customers who are struggling to pay their electric bills. The AMP will offer qualifying residential customers of UES immediate relief to reduce their current and future energy burdens through a flexible payment arrangement and arrears forgiveness program. The Company's AMP offering will also provide assistance to improve the customer's ability to better manage their payments more effectively. The direct testimony of Carole Beaulieu supports UES's proposed AMP.

G. TEMPORARY RATES

14. Pursuant to NH RSA 378:6, the Commission may suspend the effective date of UES's permanent rates Tariff pending an investigation by the Commission under NH RSA 378:5 into the reasonableness of the Permanent Rates Tariff. If the Commission suspends UES's permanent rates Tariff, UES requests that temporary rates be established in accordance with NH RSA 378:27, which provides that the Commission may, after reasonable notice and hearing, if the public interest so requires, prescribe reasonable temporary rates for the duration of a rate proceeding, sufficient to yield not less than a reasonable return on the cost of the utility's property used and useful in service to the public, less accrued depreciation.

15. UES requests that if such temporary rates are set, they be established at the levels set forth in Supplement No. 2 to NHPUC No. 3, commencing with service

rendered on June 1, 2021 and until the date a final, non-appealable order establishing permanent rates is issued. The requested temporary rates represent an increase of $5,812,761 in annual revenues, or 2.7 percent above present revenues. As shown in Attachment 1, UES proposes to recover this increase on a uniform per kWh basis from all rate classes. In support of this request, UES notes that during the twelve months ended December 31, 2020 (i.e., the test year underlying the Permanent Rates Tariff), UES earned a return on equity of approximately 6.4 percent. This amount is substantially lower than UES' authorized return on equity of 9.50 percent, and indicates that UES's current rates are causing earnings attrition.

16. UES is seeking a temporary rate increase in lieu of establishing temporary rates at current levels in order to expeditiously address the above-described earnings attrition. In addition, because the Company's under-earning situation is expected to be exacerbated by increased expenditures over the next several months, UES is in immediate need of the level of temporary rate relief indicated above. Furthermore, granting a temporary rate increase will provide for a smoother transition from current to permanent rates and will lessen the size of the difference between temporary and permanent rates to be collected from customers at the conclusion of the permanent rate case.

WHEREFORE, UES respectfully requests that the Commission:

A. Issue an order of notice which schedules a hearing upon the within Petition;

B. Following an investigation pursuant to RSA 378:5 of the reasonableness of the proposed rates and revised tariffs filed with this Petition, enter an order authorizing UES to implement such proposed rates and tariffs as permanent effective for service rendered on and after May 2, 2021;

C. If the Commission suspends UES's permanent rates Tariff, establish temporary rates in accordance with NH RSA 378:27, and, following a hearing, enter an order authorizing temporary rates at the levels set forth in Supplement No. 2 to NHPUC No. 3 for service rendered on and after June 1, 2021, until the date a final, non-appealable order establishing permanent rates is issued;

D. Pursuant to RSA 378:29, in the event that permanent rates, once determined by the Commission, exceed temporary rates, enter an order authorizing UES to collect the difference from customers;

E. Enter an order authorizing UES to implement the Step Adjustments as proposed herein; and

F. Grant such further relief as may be just and appropriate.

Respectfully submitted,

UNITIL ENERGY SYSTEMS, INC.

By its Attorneys:

Patrick H. Taylor
Senior Counsel

Gary Epler
Chief Regulatory Counsel

Unitil Service Corp.
6 Liberty Lane West
Hampton, NH 03842-1720

Dated: April 2, 2021

Certificate of Service

I hereby certify that on this 2nd day of April, 2021, a copy of the foregoing Petition was electronically delivered to the Office of Consumer Advocate.

Patrick H. Taylor

Attachment 1

Unitil Energy Systems, Inc.

Proposed Temporary Rate

Temporary Rate Increase	$5,812,761
Test Year kWh Sales	1,160,418,601
Temporary Rate $/kWh	$0.00501

TABLE OF CONTENTS TO TARIFF NO. 3

A temporary rate distribution charge of $0.00501 per kilowatt hour shall be billed by the Company to all customers taking Delivery Service from the Company.

NHPUC No. 3 - Electricity Delivery
Unitil Energy Systems, Inc.

Forty-Fifth Revised Page 4
Superseding Forty-Fourth Revised Page 4

SUMMARY OF DELIVERY SERVICE RATES

Each bill rendered for electric delivery service shall be calculated through the application of the effective rates as listed below.

Class		Distribution Charge*	Non-Transmission External Delivery Charge**	Transmission External Delivery Charge**	Total External Delivery Charge**	Stranded Cost Charge**	Storm Recovery Adjustment Factor***	System Benefits Charge**** (1)	Total Delivery Charges
D	Customer Charge	$21.07							$21.07
	All kWh	$0.04622	($0.00019)	$0.03632	$0.03613	($0.00025)	$0.00084	$0.00752	$0.09046
G2	Customer Charge	$32.20							$32.20
	All kW	$11.59				($0.05)			$11.54
	All kWh	$0.00000	($0.00019)	$0.03632	$0.03613	($0.00005)	$0.00084	$0.00752	$0.04444
G2 - kWh meter	Customer Charge	$20.28							$20.28
	All kWh	$0.00974	($0.00019)	$0.03632	$0.03613	($0.00025)	$0.00084	$0.00752	$0.05398
G2 - Quick Recovery Water Heat and/or Space Heat	Customer Charge	$10.73							$10.73
	All kWh	$0.03535	($0.00019)	$0.03632	$0.03613	($0.00025)	$0.00084	$0.00752	$0.07959
G1	Customer Charge	$178.93	Secondary Voltage						$178.93
	Customer Charge	$95.42	Primary Voltage						$95.42
	All kVA	$8.37				($0.06)			$8.31
	All kWh	$0.00000	($0.00019)	$0.03632	$0.03613	($0.00006)	$0.00084	$0.00752	$0.04443
ALL GENERAL	Transformer Ownership Credit (kW/kVa)								($0.50)
	Voltage Discount at 4,160 Volts or Over (all kW/kVA and kWh)								2.00%
	Voltage Discount at 34,500 Volts or Over (all kW/kVA and kWh)								3.50%

(1) Includes low-income portion of $0.00150 per kWh, energy efficiency portion of $0.00528 per kWh and lost base revenue portion of $0.00074 per kWh.

** Authorized by NHPUC Order No. __ in Case No. DE __, dated __*
*** Authorized by NHPUC Order No. 26,388 in Case No. DE 20-098, dated July 31, 2020*
**** Authorized by NHPUC Order No. 26,236 in Case No. DE 19-043, dated April 22, 2019*
***** Authorized by NHPUC Order No. 26,323 in Case No. DE 17-136, dated December 31, 2019*

Issued: April 2, 2021
Effective: May 2, 2021

Issued By: Robert B. Hevert
Sr. Vice President

NHPUC No. 3 - Electricity Delivery
Unitil Energy Systems, Inc.

Forty-Fifth Revised Page 5
Superseding Forty-Fourth Revised Page 5

SUMMARY OF DELIVERY SERVICE RATES (continued)

Class	Distribution Charge*	Non-Transmission External Delivery Charge**	Transmission External Delivery Charge**	External Delivery Charge**	Stranded Cost Charge**	Storm Recovery Adjustment Factor***	System Benefits Charge**** (1)	Total Delivery Charges
OL								
All kWh	$0.00000	($0.00019)	$0.03632	$0.03613	($0.00025)	$0.00084	$0.00752	$0.04424

Luminaire Charges

Category	Lamp Size Nominal Watts	Lumens (Approx.)	All-Night Service Monthly kWh	Midnight Service Monthly kWh	Description	Price Per Luminaire Per Mo.	Price Per Luminaire Per Year
Company	100	3,500	43	20	Mercury Vapor Street	$13.73	$164.76
Company	175	7,000	71	33	Mercury Vapor Street	$15.73	$188.76
Company	250	11,000	100	46	Mercury Vapor Street	$17.25	$207.00
Company	400	20,000	157	73	Mercury Vapor Street	$17.25	$207.00
Company	1,000	60,000	372	173	Mercury Vapor Street	$24.78	$297.36
Company	250	11,000	100	46	Mercury Vapor Flood	$18.25	$219.00
Company	400	20,000	157	73	Mercury Vapor Flood	$21.57	$258.84
Company	1,000	60,000	380	176	Mercury Vapor Flood	$25.29	$303.48
Company	100	3,500	48	22	Mercury Vapor Power Bracket	$13.44	$161.28
Company	175	7,000	71	33	Mercury Vapor Power Bracket	$14.65	$175.80
Company	50	4,000	23	11	Sodium Vapor Street	$13.73	$164.76
Company	100	9,500	48	22	Sodium Vapor Street	$15.73	$188.76
Company	150	16,000	65	30	Sodium Vapor Street	$17.25	$207.00
Company	250	30,000	102	47	Sodium Vapor Street	$19.53	$234.36
Company	400	50,000	161	75	Sodium Vapor Street	$24.78	$297.36
Company	1,000	140,000	380	176	Sodium Vapor Street	$42.51	$510.12
Company	150	16,000	65	30	Sodium Vapor Flood	$18.25	$219.00
Company	250	30,000	102	47	Sodium Vapor Flood	$21.57	$258.84
Company	400	50,000	161	75	Sodium Vapor Flood	$25.29	$303.48
Company	1,000	140,000	380	176	Sodium Vapor Flood	$42.89	$514.68
Company	50	4,000	23	11	Sodium Vapor Power Bracket	$13.44	$161.28
Company	100	9,500	48	22	Sodium Vapor Power Bracket	$14.65	$175.80
Company	175	8,800	74	34	Metal Halide Street	$17.25	$207.00
Company	1,000	86,000	374	174	Metal Halide Flood	$25.29	$303.48
Company	35	3,000	12	6	LED Area Light Fixture	$13.44	$161.28
Company	47	4,000	16	8	LED Area Light Fixture	$14.65	$175.80
Company	30	3,300	10	5	LED Street Light Fixture	$13.73	$164.76
Company	50	5,000	17	8	LED Street Light Fixture	$15.73	$188.76
Company	100	11,000	35	17	LED Street Light Fixture	$17.25	$207.00
Company	120	18,000	42	19	LED Street Light Fixture	$19.53	$234.36
Company	140	18,000	48	23	LED Street Light Fixture	$24.78	$297.36
Company	260	31,000	90	42	LED Street Light Fixture	$42.51	$510.12
Company	70	10,000	24	12	LED Flood Light Fixture	$18.25	$219.00
Company	90	10,000	31	14	LED Flood Light Fixture	$21.57	$258.84
Company	110	15,000	38	18	LED Flood Light Fixture	$25.29	$303.48
Company	370	46,000	128	61	LED Flood Light Fixture	$42.89	$514.68
Customer Paid	35	3,000	12	6	LED Area Light Fixture	$7.00	$84.00
Customer Paid	47	4,000	16	8	LED Area Light Fixture	$8.21	$98.52
Customer Paid	30	3,300	10	5	LED Street Light Fixture	$9.71	$116.52
Customer Paid	50	5,000	17	8	LED Street Light Fixture	$11.92	$143.04
Customer Paid	100	11,000	35	17	LED Street Light Fixture	$12.48	$149.76
Customer Paid	120	18,000	42	19	LED Street Light Fixture	$14.76	$177.12
Customer Paid	140	18,000	48	23	LED Street Light Fixture	$17.83	$213.96
Customer Paid	260	31,000	90	42	LED Street Light Fixture	$33.56	$402.72
Customer Paid	70	10,000	24	12	LED Flood Light Fixture	$11.24	$134.88
Customer Paid	90	10,000	31	14	LED Flood Light Fixture	$14.56	$174.72
Customer Paid	110	15,000	38	18	LED Flood Light Fixture	$17.36	$208.32
Customer Paid	370	46,000	128	61	LED Flood Light Fixture	$27.00	$324.00

(1) Includes low-income portion of $0.00150 per kWh, energy efficiency portion of $0.00528 per kWh and lost base revenue portion of $0.00074 per kWh.

** Authorized by NHPUC Order No. __ in Case No. DE __, dated __*
*** Authorized by NHPUC Order No. 26,388 in Case No. DE 20-098, dated July 31, 2020*
**** Authorized by NHPUC Order No. 26,236 in Case No. DE 19-043, dated April 22, 2019*
***** Authorized by NHPUC Order No. 26,323 in Case No. DE 17-136, dated December 31, 2019*

Issued: April 2, 2021
Effective: May 2, 2021

Issued By: Robert B. Hevert
Sr. Vice President

NHPUC No. 3 - Electricity Delivery
Unitil Energy Systems, Inc.

Sixty-Sixth Revised Page 6
Superseding Sixty-Fifth Revised Page 6

SUMMARY OF LOW-INCOME ELECTRIC ASSISTANCE PROGRAM DISCOUNTS

Low-Income Electric Assistance Program (LI-EAP) Discounts for Eligible Customers

				LI-EAP discount Delivery Only; Excludes Supply	**LI-EAP discount Fixed Default Service Supply Only**	**LI-EAP discount Variable Default Service Supply Only**					
Tier	Percentage of NH State Median Income & Federal Poverty Guidelines	Discount (5)	Blocks	May 2, 2021 (1)	Dec 2020-May 2021 (2)	Dec-20 (3)	Jan-21 (3)	Feb-21 (3)	Mar-21 (3)	Apr-21 (3)	May-21 (3)
1 (4)	N/A	N/A									
2	151 (FPG) - 60 (SMI)	8%	Customer Charge	($1.69)							
			First 750 kWh	($0.00724)	($0.00745)	($0.00721)	($0.00857)	($0.00870)	($0.00707)	($0.00645)	($0.00599)
			Excess 750 kWh	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
3	126 (FPG) - 150 (FPG)	22%	Customer Charge	($4.64)							
			First 750 kWh	($0.01990)	($0.02049)	($0.01982)	($0.02356)	($0.02393)	($0.01945)	($0.01773)	($0.01646)
			Excess 750 kWh	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
4	101 (FPG) - 125 (FPG)	36%	Customer Charge	($7.59)							
			First 750 kWh	($0.03257)	($0.03353)	($0.03243)	($0.03856)	($0.03916)	($0.03183)	($0.02902)	($0.02694)
			Excess 750 kWh	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
5	76 (FPG) - 100 (FPG)	52%	Customer Charge	($10.96)							
			First 750 kWh	($0.04704)	($0.04844)	($0.04684)	($0.05570)	($0.05657)	($0.04598)	($0.04191)	($0.03892)
			Excess 750 kWh	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
6	0 - 75 (FPG)	76%	Customer Charge	($16.01)							
			First 750 kWh	($0.06875)	($0.07079)	($0.06845)	($0.08140)	($0.08267)	($0.06720)	($0.06126)	($0.05688)
			Excess 750 kWh	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000

(1) Discount calculated using total utility charges from Page 4 multiplied by the appropriate discount. These figures exclude default service and are applicable to customers choosing a Competitive Supplier or self-supply. Customers taking default service from the Company would receive these discounts plus the appropriate discount applicable to default service supply. Competitively supplied customers billed on a consolidated basis would receive these discounts plus the appropriate fixed default service supply discount.

(2) Discount calculated using Non-G1 class (Residential) Fixed Default Service Rate multiplied by the appropriate discount. These figures exclude delivery.

(3) Discount calculated using Non-G1 class (Residential) Variable Default Service Rate, for the applicable month, multiplied by the appropriate discount. These figures exclude delivery.

(4) Tier 1 was eliminated by Order No. 25,200 in DE 10-192 dated March 4, 2011.

(5) Discounts effective July 1, 2016 in accordance with Order No. 25-901 in DE 14-078.

Authorized by NHPUC Order No. __ in Case No. DE __, dated __

Issued: April 2, 2021
Effective: May 2, 2021

Issued By: Robert B. Hevert
Sr. Vice President

L. “Payment Agent” shall mean any third-party authorized by a Customer to receive and pay the bills rendered by the Company for service under this Tariff.

M. “Rate Schedule” shall mean the Rate Schedules included as part of this Tariff.

N. “Tariff” shall mean this Delivery Service Tariff and all Rate Schedules, appendices and exhibits to such Tariff.

O. “Terms and Conditions” shall mean these Terms and Conditions for Distribution Service.

II. DISTRIBUTION SERVICES

1. Rates and Tariffs

A. Schedule of Rates

The Company furnishes its various services under tariffs and/or contracts (“Schedule of Rates”) promulgated in accordance with the provisions of the applicable rules of the New Hampshire Public Utilities Commission and the laws of the State of New Hampshire. Such Schedule of Rates, which includes these Terms and Conditions for Distribution Service, is available for public inspection during normal business hours at the business offices of the Company, on Unitil.com, and at the offices of the Commission.

B. Amendments; Conflicts

The Schedule of Rates may be revised, amended, supplemented or supplanted in whole or in part from time to time according to the procedures provided by Commission rules and regulations. When effective, all such revisions, amendments, supplements, or replacements will appropriately supersede the existing Schedule of Rates. If there is a conflict between the express terms of any Rate Schedule or contract approved by the Commission and these Terms and Conditions, the express terms of the Rate Schedule or contract shall govern.

C. Modification by Company

No agent or employee of the Company is authorized to modify any provision or rate contained in the Schedule of Rates or to bind the Company to perform in any manner contrary thereto. Any modification to the Schedule of Rates or any promise contrary thereto shall be in writing, duly executed by an authorized officer of the Company, subject in all cases to applicable statutes and to the orders and regulations of the Commission, and available for public inspection during normal business hours at the business offices of the Company and at the offices of the Commission.

(10) Selection of Supplier by a Customer:

Any Customer requesting or receiving Delivery Service under this Tariff is responsible for selecting or changing a Supplier. The Company shall process a change in or initiation of Generation Service within two business days of receiving a valid Electronic Enrollment from a Supplier. The Supplier must satisfy all the applicable requirements of this Tariff and the Commission's rules prior to the commencement of Generation Service. The date of change in, or initiation of, Generation Service shall commence upon the next meter reading date for the customer provided the Company receives and successfully processes the Electronic Enrollment at least two business days prior to the regularly scheduled meter reading cycle date for the Customer.

(11) Termination of Generation Service

To terminate Generation Service from a particular Supplier, a Customer may either have the Supplier of record send to the Company a "Supplier Drops Customer" transaction, in accordance with the Terms and Conditions for Energy Service Providers section of this Tariff, or request Generation Service from an alternative Supplier. Generation Service from the Supplier of record shall terminate on the next meter read date provided the Company has received either a valid "Supplier Drops Customer" notice from the Supplier of record or a valid Electronic Enrollment from a new Supplier at least two business days prior to the regularly scheduled meter read date.

E. <u>Term of Customer's Obligation to Company</u>

Each Customer shall be liable for service taken until such time as the Customer requests termination of Distribution Service and a final meter reading is recorded by the Company. The bill rendered by the Company based on such final meter reading shall be payable upon receipt. In the event that the Customer of Record hinders the Company's access to the meter or fails to give notice of termination of Distribution Service to the Company, the Customer of Record shall continue to be liable for service provided until the Company either disconnects the meter or a new party becomes a Customer of the Company at such service location. The Customer shall be liable for all costs incurred by the Company when the Customer prevents access to the Company's equipment. If the customer is a tenant, they will need to contact their landlord to provide access. If the landlord refuses pursuant to NHPUC 1203.10(c) the landlord will be responsible for all charges from the date of notice given by the customer or the date that the meter is disconnected or a new tenant takes over service whichever is first.

3. Security Deposits

A. <u>Non-Residential Accounts</u>

To protect against loss, or before rendering or restoring service under Section 6, the Company will require a deposit from all non-residential Customers in accordance with NHPUC 1203.03. The maximum amount of any security deposit required shall not exceed two times the average monthly bill or $10.00, whichever is greater. The Company may refuse to render service to all non-residential Customers for failure to make a deposit, in accordance with NHPUC 1203.03.

B. Residential Accounts

(1) New Residential Service: Pursuant to the provisions of NHPUC 1203.03(a), the Company may require a security deposit on a new residential account when:

(a) When the Customer has an undisputed overdue balance, incurred within the last three (3) years, on a prior account with the utility or any similar type of utility.

(b) When any utility has successfully obtained a judgment against the Customer during the past two (2) years for non-payment of a delinquent account for utility service.

(c) When the utility has disconnected the Customer's service within the last three (3) years because the Customer interfered with, or diverted, the service of the utility situated on or about the Customer's premises.

(d) When the customer is unable to provide satisfactory evidence to the utility that he or she intends to remain at the location for which service is being requested for a period of 12 consecutive months, unless he or she provides satisfactory evidence that he or she has not been delinquent in his or her similar utility service accounts for a period of 12 months, in which case no deposit shall be required.

(2) Existing Residential Service: Pursuant to the provisions of NHPUC 1203.03(e), the Company may require a deposit on an existing residential account when:

(a) The Customer has received four (4) disconnect notices for non-payment within a twelve (12) month period.

(b) The service has been disconnected for non-payment or a delinquent account.

(c) The Customer interfered with or diverted the service of the Company situated on or delivered on or about the Customer's premises.

(d) The Customer has filed for bankruptcy and included the Company as a creditor under the filing and the filing has been accepted. Any such deposit requirement shall be in accordance with 11 U.S.C. §366.

(3) If the Company requires a security deposit, the Company shall inform the Customer, orally and in writing, of the option to provide a third party guarantee in lieu of a deposit pursuant to the provisions of NHPUC 1203.03.

(4) The Company shall not require a residential deposit or furnish a guarantee as a condition of new or continued service based on the customer's income, home ownership, residential location, race, color, creed, sex, gender identity, sexual

orientation, marital status, age with the exception of unemancipated minors, national origin, or disability and shall make such requirement only in accordance with NHPUC 1203.03.

(5) The Company may refuse to render service to any residential Customers for failure to make a deposit, in accordance NHPUC 1203.03.

C. Termination of Service

The Company may terminate a Customer's Distribution Service if a security deposit, authorized by Sections 3.A and 3.B, above, is not made in accordance with the provisions outlined in NHPUC 1203.03 and 1204.00.

D. Refund of Deposit; Interest

Interest shall be paid on cash deposits from the date of deposit at the rate prescribed by the New Hampshire Public Utilities Commission. When a deposit has been held longer than twelve (12) months, interest shall be paid to the Customer or credited to the Customer's current bill not less than annually. Deposits plus accrued interest thereon, less any amount due the Company, will be refunded within sixty (60) days of termination of service or when satisfactory credit relations have been established over at least twelve (12) consecutive months for a residential Customer and twenty-four (24) consecutive months for a non-residential Customer.

4. Service Supplied

A. Customer Delivery Point and Metering Installation

(1) Except as noted herein, the Company shall furnish and install, at locations it designates, one or more meters for the purpose of measuring the electricity delivered. The Company may at any time change any meter it installed. Except as specifically provided by a given rate, all rates in the Schedule of Rates are predicated on service to a Customer at a single Customer Delivery Point and metering installation. Where service is supplied to an account at more than one delivery point or metering installation, each single point of delivery or metering installation shall be considered to be a separate account for purposes of applying the Schedule of Rates, except (a) if a Customer is served through multiple Customer Delivery Points or metering installations for the Company's own convenience; or (b) if otherwise approved by the Commission, or (c) if the Customer applies to the Company and the use is found to comply with the availability clauses in the Schedule of Rates.

(2) Any new or renovated domestic structure with more than one (1) dwelling unit will be metered separately and each meter will be billed as an individual Customer (NHRSA 155.D and Section 505.1 NH Energy Code). Where a business enterprise, occupation or institution occupies more than one unit or space, each unit or space will be metered separately and considered a distinct Customer, unless the Customer furnishes, owns, and maintains the necessary distribution circuits by which to connect the units.

5. Billing and Metering

A. Billing Period Defined

The basis of all charges is the billing period, defined as the time period between two consecutive regular monthly meter readings or estimates of such monthly meter readings. The standard billing period is thirty (30) days. Bills for Distribution Service will be rendered monthly.

B. Bills; Time of Payment

Unless otherwise specified, bills of the Company are payable upon receipt and may be paid online at Unitil.com, via the automated phone system, with a Customer Service Representative or with any authorized collector or agent. Bills shall be deemed paid when valid payment is received by the Company. Bills shall be deemed rendered and other notices duly given when delivered personally to the Customer or three (3) days following the date of mailing to the mailing address, or to the premises supplied, or the last known address of the Customer. The telephone number of the Company's Customer Service Center shall appear on each residential bill rendered by the Company. A statement that customers should call the NHPUC's Consumers Affairs Division for further assistance after first attempting to resolve any dispute with the Company or Competitive Supplier should also be included on each residential bill. Customer payment responsibilities with Competitive Suppliers shall be governed by the particular Customer/Competitive Supplier contract.

C. Past Due Bills

Unless otherwise stated in a Rate Schedule, each bill for Distribution Service shall be due by the date included on the bill, generally twenty-five (25) days from the bill date,. Bills paid after the due date will be subject to interest charges in accordance with NHPUC 1203.08 and Section 5.E below.

D. Failure of Payment Agent to Remit Payment

A customer who has elected to use a Payment Agent shall be treated in the same manner as other Customers in the Company's application of the applicable statues, rules and regulations of the Commission and the terms and conditions of this Tariff, notwithstanding any failure of the Payment Agent to remit payment to the Company. The Customer shall be solely responsible for all amounts due, including, but not limited to, any late payment charges.

E. Interest on Past Due Accounts

Unless otherwise stated in a Rate Schedule, bills for which valid payment has not been received within twenty-five (25) days from the bill date shall be considered past due and accrue interest on any unpaid balance, including any outstanding interest charges.

Such interest rate shall be determined in accordance with NHPUC 1203.08. Such interest charge shall be paid from the date thereof until the date of payment.

F. Billing for Generation Service

The Company shall provide a single bill, reflecting unbundled charges for electric service, to Customers who receive Default Service.

The Company shall offer two billing service options to Competitive Suppliers providing Generation Service to Customers: A) Standard Bill Service; and B) Consolidated Bill Service, as set forth in the Terms and Conditions for Competitive Suppliers, Section III.6.A. and III.6.B. The Competitive Supplier shall inform the Distribution Company of the selected billing option, in accordance with the rules and procedures set forth in the EDI Working Group Report.

G. Generation Source

The Company shall reasonably accommodate a change from Default Service or Generation Service to a new Competitive Supplier in accordance with the rules as developed by the EDI working group.

H. Actual Meter Readings; Estimates

The Company shall make an actual meter reading at least every third billing period. If a meter is not scheduled to be read in a particular month, or if the Company is unable to read the meter when scheduled, or if the meter for any reason fails to register the correct amount of electricity supplied or the correct demand of any Customer for a period of time, the Company shall make a reasonable estimate of the consumption of electricity during those months when the meter is not read or is not registering properly, based on available data, and such estimated bills shall be payable as rendered.

I. Optional Customer Meter Readings

Any Customer who would otherwise receive an estimated bill pursuant to Section 5.H, above, may elect to receive a bill based on a Customer meter reading by reading his/her meter on the date prescribed by the Company.

J. Constant Use Installation

The Company may calculate rather than meter the kilowatt demand and kilowatt-hours used by any installation for which the demand and hours-use are definitely known.

K. Determination of Customer's Demand

Where a rate requires determination of maximum demand, it shall be determined by measurement or estimated as provided by the rate or where applicable by the provisions of the following paragraphs of this section.

(1) When measured, the demand shall be based upon the greatest rate of taking service during a fifteen (15) minute interval except that it may be based upon a shorter interval when of an instantaneous or widely fluctuating character.

(2) When the nature of the load served is of an intermittent, instantaneous or widely fluctuating character such as to render demand meter readings of doubtful value as compared to the actual capacity requirements, the demand may be determined on the basis of a time interval less than that specified, or on the basis of the minimum transformer capacity necessary to render the service, or the minimum load limiting device rating necessary to permit continuous uninterrupted service. In all such instances, the Company will document the basis of demand determination.

L. Access to Meters

A properly identified and authorized representative of the Company shall have the right to gain access at all reasonable times and intervals for the purpose of reading, installing, examining, testing, repairing, replacing, or removing the Company's meters, meter reading devices, wires, or other electrical equipment and appliances, or of discontinuing service, in accordance with the applicable laws of the State of New Hampshire, rules and regulations of the Commission, and Company policy in effect from time to time, and the Customer or Landlord/Owner of the building shall not prevent or hinder the Company's access.

M. Diversion and Meter Tampering

If a Customer receives unmetered service as the result of any tampering with the meter or other Company equipment, the Company shall take appropriate corrective action including, but not limited to, making changes in the meter or other equipment and rebilling the Customer. The Customer may be held responsible to the Company for the receipt of Distribution Service not registered on the meter.

N. Returned Check Fee

The Company may assess a returned check fee pursuant to Section 10, below, to any Customer whose check made payable to the Company is dishonored by any bank when presented for payment by the Company. Receipt of a check or payment instrument that is subsequently dishonored shall not be considered valid payment.

O. Collection of Taxes

The Company shall collect all sales, excise, or other taxes imposed by governmental authorities with respect to the delivery of electricity. The Customer shall be responsible for identifying and requesting any exemption from the collection of the tax by filing appropriate documentation with the Company.

(1) *Simultaneous purchase and sale* is an arrangement whereby a QF's entire output is considered to be sold to the utility, while power used internally by the QF is considered to be simultaneously purchased from the Company through Default Service or from a Competitive Supplier.

(2) *Net purchases or sale* is an arrangement whereby output of a QF is considered to be used to the extent needed for the QF's internal needs, while any additional power needed by the QF is purchased from the Company through Default Service or from a Competitive Supplier, or any surplus power generated by the QF is sold to the Company as surplus.

(3) *Internal use only* is an arrangement whereby output of the QF is used entirely for internal needs. The Customer's meter is detented, to stop the meter from going backwards in case of any inadvertent flow into the Company's System.

G. Inspection of Customer's Premises

The Company reserves the right to make an inspection of the Customer's premises before rendering service in order to see that its rules are complied with. Neither by inspection or non-rejection of service, nor in any other way, does the Company give any warranty, express or implied, as to the adequacy, safety or other characteristics of any structures, equipment, wiring, appliances or devices which utilize electricity and are owned, installed or maintained by the Customer or leased by the Customer from third parties.

8. Company's Installation

A. Information and Requirements for Distribution Service

Upon request, the Company shall furnish to any person detailed information on the method and manner of making service connections. Such detailed information may include a copy of the Company's Information and Requirements Booklet, a description of the service available, connections necessary between the Company's facilities and the Customer's premises, location of entrance facilities and metering equipment, and Customer and Company responsibilities for installation of facilities.

B. Interference with Company Property

All meters, services, and other electric equipment owned by the Company, regardless of location, shall be and will remain the property of the Company; and no one other than an employee or authorized agent of the Company shall be permitted to remove, operate, or maintain such property. The Customer shall not interfere with or alter the meter, seals or other property used in connection with the rendering of service or permit the same to be done by any person other than the authorized agents or employees of the Company. The Customer shall be responsible for all damage to or loss of such property unless occasioned by circumstances beyond the Customer's control. Such property shall be installed at points most convenient for the Company's access and service and in conformance with public regulations in force from time to time. The costs of relocating such property shall be borne by the Customer when done at the Customer's request, for

(2) Access to Company Equipment: The Company shall have free and safe access to its equipment located on the Customer's premises at all times, including but not limited to subsurface structures, above ground enclosures, and pad mounted equipment, and the Customer shall authorize and/or obtain his landlord's permission for such access. If the Company is denied free access to said property, the equipment shall be relocated or removed at the Customer's expense. Ornamental shrubs and/or other types of vegetation may be removed by the Company in order to access its equipment, and such removal shall be done at the customer's expense. The Customer shall not knowingly permit access to Company's equipment except by authorized employees of the Company.

9. Company Liability

A. <u>Emergency Interruption of Service</u>

Whenever the Company reasonably believes the integrity of the Company's system or the supply of electricity to be threatened by conditions on its system or upon the systems with which it is directly or indirectly interconnected, the Company, may in the exercise of reasonable judgment, curtail or interrupt electric service or reduce voltage, and such action shall not be construed to constitute a default nor shall the Company be liable therefor in any respect. The Company will use reasonable efforts under the circumstances to overcome the cause of such curtailment, interruption, or reduction and to resume full performance.

B. <u>Planned Interruption of Service</u>

The Company may, in the exercise of reasonable judgment, curtail or interrupt electric service or reduce voltage for the purposes of planned maintenance, installation or replacement. When such curtailment is necessary, the Company shall conduct such work at a time causing the minimum inconvenience to customers consistent with the circumstances. The Company shall, if practical, notify customers in advance that might be seriously affected by interruptions to service. The Company will provide notice to any customer of whom it is previously aware who would encounter a potentially life-threatening situation as a result of the planned interruptions. A potentially life-threatening situation for this purpose shall include life support equipment or other potentially life-threatening medical situations. Such action shall not be construed to constitute a default nor shall the Company be liable therefor in any respect.

C. <u>Non-Performance Due to Force Majeure</u>

The Company shall be excused from performing under the Schedule of Rates and shall not be liable in damages or otherwise if and to the extent that it shall be unable to do so or prevented from doing so by statute or regulation or by action of any court or public authority having or purporting to have jurisdiction in the premises, or by loss, diminution, or impairment of electrical service from its generating plants or suppliers or the systems of others with which it is interconnected, or by a break or fault in its transmission or distribution system; failure or improper operation of transformers, switches, or other equipment necessary for electric distribution, or by reason of storm, flood, fire, earthquake, explosion, civil disturbance, labor difficulty, act of God, or public enemy,

CHARACTER OF SERVICE

Electricity will normally be delivered at 120/240 volts using three wire, single phase service. In some areas service may be 120/208 volts, three wire, single phase.

DELIVERY SERVICE CHARGES - MONTHLY

The Delivery Service Charges shall include Distribution Charges and Adjustments, set forth below. The Distribution Charges are subject to annual adjustment as approved in DE 21-030.

DISTRIBUTION CHARGES - MONTHLY

Customer Charge:	\$21.07 per meter
Distribution Charge:	4.622¢ per kWh

MINIMUM CHARGE

The minimum charge per month, or fraction thereof, shall be the Customer Charge.

ADJUSTMENTS

These Adjustments, included in the Delivery Service Charges, shall be adjusted from time to time.

External Delivery Charge: All energy delivered under this Schedule shall be subject to the External Delivery Charge as provided in Schedule EDC of the Tariff of which this is a part.

Stranded Cost Charge: All energy delivered under this Schedule shall be subject to the Stranded Cost Charge as provided in Schedule SCC of the Tariff of which this is a part.

Storm Recovery Adjustment Factor: All energy delivered under this Schedule shall be subject to the Storm Recovery Adjustment Factor as provided in Schedule SRAF of the Tariff of which this is a part.

System Benefits Charge: All energy delivered under this Schedule shall be subject to the System Benefits Charge as provided in Schedule SBC of the Tariff of which this is a part.

Revenue Decoupling Adjustment Charge: All energy delivered under this Schedule shall be subject to the Revenue Decoupling Adjustment Charge as provided in Schedule RDAC of the Tariff of which this is a part.

Default Service Charge: For Customers receiving Default Service from the Company, all energy delivered under this Schedule shall be subject to the Default Service Charge as provided in Schedule DS of the Tariff of which this is a part.

LOW INCOME ENERGY ASSISTANCE PROGRAM

Customers taking service under this rate may be eligible to receive discounts under the statewide low-income electric assistance program ("LI-EAP") authorized by the New Hampshire Public Utilities Commission. Eligibility for the LI-EAP shall be determined by the Community Action Agencies. Customers participating in the LI-EAP will continue to take service under this rate, but will receive a discount as provided under this Tariff as applicable.

AVAILABILITY

Service is available under this Schedule to non-domestic Customers for all general purposes and includes the operation of single phase motors having such characteristics and so operated as not to impair service to other Customers. Single phase motors exceeding five (5) horsepower will be allowed only upon approval by the Company in each instance. Unmetered traffic and flashing signal lights existing immediately prior to the effective date of this Schedule shall also be billed under this Schedule.

This Schedule is for delivery service only. Customers are required to obtain an energy supply from a Competitive Supplier, self-supply (available to Market Participant End Users as described in NHPUC Order No. 24,172), or may be eligible for Default Service from the Company pursuant to Schedule DS as amended from time to time.

CHARACTER OF SERVICE

Electric service of the following description is available, depending upon the location of the Customer: (1) 120/240 volts, single phase, three wire; (2) 120/208 volts, single phase, three wire; (3) 208Y/120 volts, three phase, four wire; (4) 480Y/277 volts, three phase, four wire; (5) 4160 volts, three phase, four wire or such higher primary distribution voltage as may be available, the voltage to be designated by the Company.

DELIVERY SERVICE CHARGES – MONTHLY

The Delivery Service Charges shall include Distribution Charges and Adjustments, set forth below. The Distribution Charges are subject to annual adjustment as approved in DE 21-030.

Large General Service Schedule G1: for any industrial or commercial Customer with its average use consistently equal to or in excess of two hundred (200) kilovolt-amperes of demand and/or generally greater than or equal to one-hundred thousand (100,000) kilowatt-hours per month.

DISTRIBUTION CHARGES - MONTHLY

Customer Charge:	Secondary Voltage	$178.93 per meter
	Primary Voltage	$95.42 per meter
Distribution Charges:	$8.37 per kVA	
	0.000¢ per kWh	

Regular General Service Schedule G2: for any industrial or commercial Customer with its average use consistently below two-hundred (200) kilovolt-amperes of demand and/or generally less than one-hundred thousand (100,000) kilowatt-hours per month.

DISTRIBUTION CHARGES - MONTHLY

Customer Charge:	$32.20 per meter
Distribution Charges:	$11.59 per kW 0.000¢ per kWh

Regular General Service Schedule G2 kWh meter: Service is available under this Schedule only to Customers at locations which were receiving service under Unitil Energy Systems, Inc.'s NHPUC No. 1 and are presently receiving service under this Schedule. New Customers at existing locations and new locations shall not be eligible for this rate, but the Company will install a demand meter and the location shall be served under Schedule G2. Customers who have installed distributed generation shall not be eligible for this rate but shall be served under Schedule G2.

DISTRIBUTION CHARGES - MONTHLY

Customer Charge:	$20.28 per meter
Distribution Charge:	0.974¢ per kWh

Uncontrolled (Quick Recovery) Water Heating: Uncontrolled (Quick Recovery) Water Heating is available under this Schedule at those locations which were receiving uncontrolled (Quick Recovery) water heating service under Unitil Energy Systems, Inc.'s NHPUC No. 1 and are presently receiving service under this Schedule.

For those locations which qualify under the preceding paragraph, uncontrolled quick recovery water heating service is available under this Schedule if the Customer has installed and in regular operation throughout the entire year an electric water heater of the quick recovery type, equipped with two thermostatically operated heating elements, each with a rating of no more than 4,500 watts, so connected and interlocked that they cannot operate simultaneously and if the water heater supplies the Customer's entire water heating requirements, all electricity supplied thereto under this provision will be metered separately and billed as follows:

DISTRIBUTION CHARGES - MONTHLY

Customer Charge:	$10.73 per meter
Distribution Charge:	3.535¢ per kWh

Space Heating: Space Heating is available under this Schedule at those locations which were receiving space heating service under Unitil Energy Systems, Inc.'s NHPUC No. 1 and are presently receiving service under this Schedule. Customers who qualify for service under this Schedule for five (5) kilowatts or more of permanently-installed space heating equipment under this provision may elect to have such service metered separately and billed as follows:

DISTRIBUTION CHARGES - MONTHLY

Customer Charge:	$10.73 per meter
Distribution Charge:	3.535¢ per kWh

DETERMINATION OF DEMAND

Large General Service Schedule G1

For the purpose of demand billing under the Large General Service Schedule G1, metered demands shall be measured as the highest 15-minute integrated kilovolt-ampere (kVA) demand determined during the current month for which the bill is rendered. The monthly billing demand charge shall be based upon this metered demand except that it shall not be less than 80% of the highest demand in any of the immediately preceding eleven months, and in no event shall such demand be taken or considered as being less than 50 kVA.

Regular General Service Schedule G2

The metered demand used for billing shall be the maximum fifteen-minute kilowatt (kW) demand determined during the current month, but in no case less than one kW or the minimum available demand capacity specified by an agreement between the Customer and the Company. The billing demand shall be taken in 0.1 kW intervals, and those demands falling between the intervals shall be billed on the next lower 0.1 kW.

If the Customer's average use is consistently equal to or in excess of two-hundred (200) kilovolt-ampere (kVA) of demand and/or is generally greater than one-hundred thousand (100,000) kilowatt-hours per month, as measured by the Company, the Customer may be placed on rate
G1.

The Company reserves the right to install kilovolt-ampere meters, and in such case the monthly demand shall not be less than 90% of the measured kVA.

METERING

The Company may at its option meter at the Customer's utilization voltage or on the high tension side of the transformer through which service is furnished.

In the latter case, or if the Customer's utilization voltage requires no transformation, and if the Company meters service at 4,160 volts or over, a compensating deduction of 2.0% will be made from the metered kilowatt or kilovolt-ampere demand and metered kilowatt-hour usage to determine billing amounts. If the Company meters service at 34,500 volts or over, a compensating deduction of 3.5% will be made from the metered kilowatt or kilovolt-ampere demand and metered kilowatt-hour usage to determine billing amounts. Demands for these purposes will be as determined under the Determination of Demand provision of this Schedule.

CREDIT FOR TRANSFORMER OWNERSHIP

If the Customer furnishes all transformers which may be required so that the Company is not required to furnish any transformers, there will be credited, against the amount established under the Determination of Demand and Metering provisions of this Schedule, 50 cents for each kilowatt of monthly billing demand, or 50 cents for each kilovolt-ampere of monthly billing demand.

MINIMUM CHARGE

The Minimum Charge per month or fraction thereof will be as follows:

Large General Service Schedule G1:

The Minimum Charge per month shall be no less than the Customer Charge for each type of service installed plus a capacity charge based upon a minimum demand and/or demand ratchet as defined under the Determination of Demand provision of this Schedule.

Regular General Service Rates G2:

The Minimum Charge per month shall be no less than the Customer Charge for each type of service installed plus a capacity charge based upon a minimum demand as defined under the Determination of Demand provision of this Schedule.

G2 kWh meter, Uncontrolled (Quick Recovery) Water Heating, and Space Heating:

The Minimum Charge per month shall be the Customer Charge for each type of service installed.

ADJUSTMENTS

These Adjustments, included in the Delivery Service Charges, shall be adjusted from time to time.

External Delivery Charge: All energy delivered under this Schedule shall be subject to the External Delivery Charge as provided in Schedule EDC of the Tariff of which this is a part.

Stranded Cost Charge: All energy delivered under this Schedule shall be subject to the Stranded Cost Charge as provided in Schedule SCC of the Tariff of which this is a part.

Storm Recovery Adjustment Factor: All energy delivered under this Schedule shall be subject to the Storm Recovery Adjustment Factor as provided in Schedule SRAF of the Tariff of which this is a part.

System Benefits Charge: All energy delivered under this Schedule shall be subject to the System Benefits Charge as provided in Schedule SBC of the Tariff of which this is a part.

Revenue Decoupling Adjustment Charge: All energy delivered under this Schedule shall be subject to the Revenue Decoupling Adjustment Charge as provided in Schedule RDAC of the Tariff of which this is a part.

Default Service Charge: For Customers receiving Default Service from the Company, all energy delivered under this Schedule shall be subject to the Default Service Charge as provided in Schedule DS of the Tariff of which this is a part.

determined be less than a) the capacity installed by the Company on a network system, b) 80% of the kilovolt-ampere rating of the transformers installed for supplying service to the Customer, or c) 80% of the Customer's total electrical requirements, as determined by the Company.

(d) Minimum Charge

An amount equal to the total of the Customer Charge and the Distribution Demand Charge as provided for Customers taking standard delivery service under this Schedule.

(e) Parallel Operation

The Customer shall at no time operate any other source of electricity supply in parallel with the service furnished by the Company except with the written consent of the Company.

(f) Term of Contract

The initial term of service hereunder shall not be less than five years unless the Customer discontinues Customer's other source of electrical power and takes all Customer's delivery service requirements from the Company.

(g) Auxiliary Energy Supply

Energy supply for Auxiliary Service is available from the Company via Default Service pursuant to Schedule DS as amended from time to time, and may be available from Competitive Suppliers.

(h) Special Provision

If the Customer is supplied from transformers also supplying other Customers, the Company may require the Customer to install a service or main switch or circuit breaker as specified by the Company.

TARIFF PROVISIONS

The Company's complete Tariff where not inconsistent with any specific provisions hereof, is a part of this rate.

AVAILABILITY

This Schedule is available to governmental bodies and private Customers for unmetered outdoor lighting service supplied from the Company's existing overhead conductors with lighting fixtures mounted on existing poles. Mercury Vapor lighting fixtures will be unavailable at new locations after December 1, 2002. Starting January 1, 2023, the Company will no longer offer sodium vapor and metal halide luminaires. From that date on, as these legacy fixtures need replacement, they will be replaced with light emitting diode ("LED") fixtures, and there will be no special charges to the customer for this replacement. If, however, a customer requests a conversion of a legacy fixture, or multiple fixtures, to LED service in advance of its actual need, requirement for replacement, or Company planned servicing, the Company may require the customer to pay all or a portion of the costs of the conversions as specified under SPECIAL PROVISIONS parts d. and e. below. Conversions are also contingent upon the availability of Company personnel and/or other resources necessary to perform the conversion.

This Schedule is for delivery service only. Customers are required to obtain an energy supply from a Competitive Supplier, self-supply (available to Market Participant End Users as described in NHPUC Order No. 24,172), or may be eligible for Default Service from the Company pursuant to Schedule DS as amended from time to time.

LIMITATIONS ON AVAILABILITY

The availability of this rate to any Customer is contingent upon the availability to the Company of personnel and/or other resources necessary to perform the conversion of existing fixtures in accordance with the time schedule specified in the Service Agreement.

CHARACTER OF SERVICE

All lighting shall be photoelectrically controlled. The Company will furnish and maintain the equipment hereinafter described and shall supply service at which the lamps are designed to operate. All lighting fixtures will be group relamped in accordance with the lamp manufacturer's suggested schedule. At relamping time the fixture will be maintained in accordance with the fixture manufacturer's suggested procedures.

DELIVERY SERVICE CHARGES – MONTHLY

The Delivery Service Charges shall include Distribution Charges and Adjustments, set forth below. The Distribution Charges are subject to annual adjustment as approved in DE 21-030.

DISTRIBUTION CHARGES: LUMINAIRE – MONTHLY

Distribution Charge: 0.000¢ per kWh

Lamp Size Nominal Watts	Lamp Size Lumens Approx.	Description of Luminaire	Luminaire Price per Month	All-Night Service Option Luminaire Monthly kWh	Midnight Service Option Luminaire Monthly kWh
100	3,500	Mercury Vapor Street	$13.73	43	20
175	7,000	Mercury Vapor Street	$15.73	71	33
250	11,000	Mercury Vapor Street	$17.25	100	46
400	20,000	Mercury Vapor Street	$17.25	157	73
1,000*	60,000	Mercury Vapor Street	$24.78	372	173
250	11,000	Mercury Vapor Flood	$18.25	100	46
400	20,000	Mercury Vapor Flood	$21.57	157	73
1,000	60,000	Mercury Vapor Flood	$25.29	380	176
100	3,500	Mercury Vapor Power Bracket	$13.44	48	22
175	7,000	Mercury Vapor Power Bracket	$14.65	71	33
50	4,000	Sodium Vapor Street	$13.73	23	11
100	9,500	Sodium Vapor Street	$15.73	48	22
150	16,000	Sodium Vapor Street	$17.25	65	30
250	30,000	Sodium Vapor Street	$19.53	102	47
400	50,000	Sodium Vapor Street	$24.78	161	75
1,000*	140,000	Sodium Vapor Street	$42.51	380	176
150	16,000	Sodium Vapor Flood	$18.25	65	30
250	30,000	Sodium Vapor Flood	$21.57	102	47
400	50,000	Sodium Vapor Flood	$25.29	161	75
1,000	140,000	Sodium Vapor Flood	$42.89	380	176
50	4,000	Sodium Vapor Power Bracket	$13.44	23	11
100	9,500	Sodium Vapor Power Bracket	$14.65	48	22
175	8,800	Metal Halide Street	$17.25	74	34
1,000	86,000	Metal Halide Flood	$25.29	374	174
35	3,000	LED Area Light Fixture	$13.44	12	6
47	4,000	LED Area Light Fixture	$14.65	16	8
30	3,300	LED Street Fixture	$13.73	10	5
50	5,000	LED Street Fixture	$15.73	17	8
100	11,000	LED Street Fixture	$17.25	35	16
120	18,000	LED Street Fixture	$19.53	42	19
140	18,000	LED Street Fixture	$24.78	48	23
260	31,000	LED Street Fixture	$42.51	90	42
70	10,000	LED Flood Light Fixture	$18.25	24	11
90	10,000	LED Flood Light Fixture	$21.57	31	14
110	15,000	LED Flood Light Fixture	$25.29	38	18
370	46,000	LED Flood Light Fixture	$42.89	128	60

* 1,000 Watt Mercury Vapor Street and 1,000 Watt Sodium Vapor Street are no longer available. Flood lights are available with brackets and ballasts as specified by the Company.

The prices and monthly kWh specified in this table for LED fixtures will apply to luminaires +/- 5 watts above or below the stated wattage in accordance with ANSI C136-15-2020 to accommodate the evolution of LED lighting fixtures.

MONTHLY KWH PER LUMINAIRE

For billing purposes on Energy based charges and adjustments, the monthly kWh figures shown in the table above under Distribution Charges - Monthly: Luminaire shall be used for each luminaire and service option type.

OTHER FIXTURES AND EQUIPMENT

Lighting fixtures other than that specified herein will be provided only at prices and for a contract term to be mutually agreed upon between the Company and the Customer.

MINIMUM CHARGE

The minimum charge per month, or fraction thereof, per lamp shall be the Distribution Charge: Luminaire.

ADJUSTMENTS

These Adjustments, included in the Delivery Service Charges, shall be adjusted from time to time.

External Delivery Charge: All energy delivered under this Schedule shall be subject to the External Delivery Charge as provided in Schedule EDC of the Tariff of which this is a part.

Stranded Cost Charge: All energy delivered under this Schedule shall be subject to the Stranded Cost Charge as provided in Schedule SCC of the Tariff of which this is a part.

Storm Recovery Adjustment Factor: All energy delivered under this Schedule shall be subject to the Storm Recovery Adjustment Factor as provided in Schedule SRAF of the Tariff of which this is a part.

System Benefits Charge: All energy delivered under this Schedule shall be subject to the System Benefits Charge as provided in Schedule SBC of the Tariff of which this is a part.

Revenue Decoupling Adjustment Charge: All energy delivered under this Schedule shall be subject to the Revenue Decoupling Adjustment Charge as provided in Schedule RDAC of the Tariff of which this is a part.

Default Service Charge: For Customers receiving Default Service from the Company, all energy delivered under this Schedule shall be subject to the Default Service Charge as provided in Schedule DS of the Tariff of which this is a part.

TERMS OF PAYMENT

The charges for service hereunder are net, billed monthly and due within 25 days following the date postmarked on the bill, as specified in the Terms and Conditions for Distribution Service, which is a part of this Tariff.

TERM OF CONTRACT

Except as provided in the Special Provisions section, service under this Schedule shall be for an initial period of one year with automatic one year extensions thereafter until cancelled by either the Customer or the Company giving to the other notice in writing at least 30 days in advance.

SPECIAL PROVISIONS

(a) Hours of Operation

Approximate hours of operation under the all-night service option will be from one-quarter hour after sunset to one-quarter hour before sunrise. Annual burn hours of 4150 are estimated for billing kWh purposes for the all-night service option. Approximate hours of operation under the midnight service option will be from one-quarter hour after sunset to midnight. Annual burn hours of 1,930 are estimated for billing kWh purposes for the midnight service option.

(b) Lamp Replacement

The Company shall replace defective lamps as promptly as possible during regular working hours, after having been advised as to the need of such replacement by the Customer.

(c) Change of Location

The Company will, at the expense to the Customer, change the location of such fixtures as the Customer may order.

(d) Change/Removal of Fixture

The Company will change the type of lighting fixture at the Customer's request, but may require the Customer to reimburse the Company for all or part of the depreciated cost of the retired equipment including installation and cost of removal, less any salvage value thereon.

(e) Conversion to LED

If a Customer requests multiple conversions of fixtures from Mercury Vapor to LED, or from High Pressure Sodium to LED, the Company may, in addition to the provisions of section (d) above, require the Customer to pay all or a portion of the costs of the conversions, including labor, material, traffic control, and overheads. Conversions to High Pressure Sodium or Metal Halide are no longer offered.

Lamp Size Nominal Watts	Lumens Approx.	Description of Luminaire	Luminaire Price per Month	All-Night Service Option Luminaire Monthly kWh	Midnight Service Option Luminaire Monthly kWh
35	3,000	LED Area Light Fixture	$7.00	12	6
47	4,000	LED Area Light Fixture	$8.21	16	8
30	3,300	LED Street Fixture	$9.71	10	5
50	5,000	LED Street Fixture	$11.92	17	8
100	11,000	LED Street Fixture	$12.48	35	16
120	18,000	LED Street Fixture	$14.76	42	19
140	18,000	LED Street Fixture	$17.83	48	23
260	31,000	LED Street Fixture	$33.56	90	42
70	10,000	LED Flood Light Fixture	$11.24	24	11
90	10,000	LED Flood Light Fixture	$14.56	31	14
110	15,000	LED Flood Light Fixture	$17.36	38	18
370	46,000	LED Flood Light Fixture	$27.00	128	60

The prices and monthly kWh specified in this table for LED fixtures will apply to luminaires +/- 5 watts above or below the stated wattage in accordance with ANSI C136-15-2020 to accommodate the evolution of LED lighting fixtures.

MONTHLY KWH PER LUMINAIRE

For billing purposes on Energy based charges and adjustments, the monthly kWh figures shown in the table above under Distribution Charges - Monthly: Luminaire shall be used for each luminaire and service option type.

OTHER LED FIXTURES AND LED EQUIPMENT

Lighting fixtures other than that specified herein will be provided only at prices and for a contract term to be mutually agreed upon between the Company and the Customer.

MINIMUM CHARGE

The minimum charge per month, or fraction thereof, per lamp shall be the Distribution Charge: Luminaire.

ADJUSTMENTS

These Adjustments, included in the Delivery Service Charges, shall be adjusted from time to time.

External Delivery Charge: All energy delivered under this Schedule shall be subject to the External Delivery Charge as provided in Schedule EDC of the Tariff of which this is a part.

Stranded Cost Charge: All energy delivered under this Schedule shall be subject to the Stranded Cost Charge as provided in Schedule SCC of the Tariff of which this is a part.

Storm Recovery Adjustment Factor: All energy delivered under this Schedule shall be subject to the Storm Recovery Adjustment Factor as provided in Schedule SRAF of the Tariff of which this is a part.

System Benefits Charge: All energy delivered under this Schedule shall be subject to the System Benefits Charge as provided in Schedule SBC of the Tariff of which this is a part.

Revenue Decoupling Adjustment Charge: All energy delivered under this Schedule shall be subject to the Revenue Decoupling Adjustment Charge as provided in Schedule RDAC of the Tariff of which this is a part.

Default Service Charge: For Customers receiving Default Service from the Company, all energy delivered under this Schedule shall be subject to the Default Service Charge as provided in Schedule DS of the Tariff of which this is a part.

TERMS OF PAYMENT

The charges for service hereunder are net, billed monthly and due within 25 days following the date postmarked on the bill, as specified in the Terms and Conditions for Distribution Service, which is a part of this Tariff.

TERM OF CONTRACT

Except as provided in the Special Provisions section, service under this Schedule shall be for an initial period of one year with automatic one year extensions thereafter until cancelled by either the Customer or the Company giving to the other notice in writing at least 30 days in advance.

MAINTENANCE

The Company shall exercise reasonable diligence to insure that all lamps are burning and shall make replacements promptly when notified of outages. However, the Company shall not be required to perform any replacements or maintenance except during regular working hours.
The Company will be responsible for correcting UES system voltage problems at no charge to the Customer. When the Company responds to a report of a non-working fixture not related to voltage, the Customer will be assessed a per-fixture per-visit charge to replace photoelectric

The External Delivery Charge ("EDC"), as specified on Calculation of the External Delivery Charge, shall be billed by the Company to all customers taking Delivery Service from the Company. The purpose of the EDC is to recover, on a fully reconciling basis, the costs billed to the Company by Other Transmission Providers as well as third party costs billed to the Company for energy and transmission related services and other costs approved by the Commission as specified herein.

The EDC shall include the following charges, except that third party costs associated with Default Service shall be included in the Default Service Charge: 1) charges billed to the Company by Other Transmission Providers as well as any charges relating to the stability of the transmission system which the Company is authorized to recover by order of the regulatory agency having jurisdiction over such charges, 2) transmission-based assessments or fees billed by or through regulatory agencies, 3) costs billed by third parties for load estimation and reconciliation and data and information services necessary for allocation and reporting of supplier loads, and for reporting to, and receiving data from, ISO New England, 4) legal and consulting outside service charges related to the Company's transmission and energy obligations and responsibilities, including legal and regulatory activities associated with the independent system operator ("ISO"), New England Power Pool ("NEPOOL"), regional transmission organization ("RTO") and Federal Energy Regulatory Commission ("FERC"), and Commission approved special assessments charged to the Company due to the expenses of experts employed by the Office of Consumer Advocate pursuant to the provisions of RSA 363:28,III. 5) the costs of Administrative Service Charges billed to the Company by Unitil Power Corp. under the FERC-approved Amended Unitil System Agreement, 6) Effective July 1, 2014, in accordance with RSA 363-A:6, amounts above or below the total NHPUC Assessment, less amounts charged to base distribution and Default Service, and 7) cash working capital associated with Other Flow-Through Operating Expenses. In addition, the EDC shall include the calendar year over- or under-collection from the Company's Vegetation Management Program and Reliability Enhancement Program. The over- or under- collection shall be credited or charged to the EDC on May 1 of the following year, or, with approval of the Commission, the Company may credit unspent amounts to future Vegetation Management Program expenditures.

Also, as approved in Docket DE 21-030, the EDC shall include the over- or under-collection of the following costs compared to the level included in distribution rates: (1) delivery write offs, (2) Arrearage Management Program costs, (3) waived late payment fee charges, and (4) wheeling revenue. The over- or under- collection shall be credited or charged to the EDC on May 1 of the following year. In addition, the EDC shall recover (1) deferred Calypso storm charges, (2) Electric Vehicle ("EV") rebate costs, and (3) EV and Time of Use marketing, communications, and education plan costs. The EDC shall also include a charge for the recovery of displaced distribution revenue associated with net metering from 2013 until such time as the Company implements decoupling. Lastly, the EDC shall include the prudently incurred costs, as approved by the Commission, associated with the alternative net metering tariff approved in

Docket DE 16-576, including: net metering credits; meters installed and related data management; independent monitoring services, bi-directional and production meters installed and related data management systems and processes; pilot programs; studies; and data collection, maintenance and dissemination. For purposes of this Schedule, "Other Transmission Provider" shall be defined as any transmission provider and other regional transmission and/or operating entities, such as NEPOOL, a regional transmission group, an ISO, and their successors, or other such body with the oversight of regional transmission, in the event that any of these entities are authorized to bill the Company directly for their services.

The EDC shall be established annually based on a forecast of includable costs, and shall also include a full reconciliation with interest for any over- or under-recoveries occurring in prior year(s). Interest shall be calculated at the prime rate, with said prime rate to be fixed on a quarterly basis and to be established as reported in THE WALL STREET JOURNAL on the first business day of the month preceding the calendar quarter. If more than one interest rate is reported, the average of the reported rates shall be used. The Company may file to change the EDC at any time should significant over- or under-recoveries occur or be expected to occur. In addition, the Company's annual filing shall breakdown the EDC into two components (transmission and non-transmission) for purposes of billing under the alternative net metering tariff that became effective September 1, 2017.

Any adjustment to the EDC shall be in accordance with a notice filed with the Commission setting forth the amount of the proposed charge and the amount of the increase or decrease. The notice shall further specify the effective date of such charge, which shall not be earlier than forty-five days after the filing of the notice, or such other date as the Commission may authorize. The annual adjustment to the EDC shall be derived in the same manner as that provided by Calculation of the External Delivery Charge.

1.0 PURPOSE

The purpose of the Revenue Decoupling Adjustment Clause (“RDAC”) is to establish procedures that allow the Company to adjust, on an annual basis, rates for distribution service that reconcile Actual Base Revenues per Customer with Authorized Base Revenues per Customer.

2.0 EFFECTIVE DATE

The Revenue Decoupling Adjustment Factor (“RDAF”) shall be effective on the first day of the Adjustment Period, as defined in Section 4.0.

3.0 APPLICABILITY

The RDAF shall apply to the Company’s Domestic Delivery Service (Schedule D), Domestic Delivery Service (Schedule D-TOU) and General Delivery Service (Schedule G), as determined in accordance with the provisions of this Tariff.

4.0 DEFINITIONS

The following definitions shall apply throughout the Tariff:

1. Actual Base Revenues is the revenue collected for a Customer Class through the Company’s customer charge and distribution charges. This excludes revenues collected through the RDAF.

2. Actual Number of Customers is the number of customers for the applicable customer class. Actual Number of Customers shall be based on the monthly equivalent bills for a customer class.

3. Actual Base Revenues per Customer is Actual Base Revenues divided by the Actual Number of Customers for a Customer Class.

4. Adjustment Period is the 12-month period for which the RDAF will be applied for each applicable customer class. The first Adjustment Period shall be the twelve-month period from August 1, 2023 to July 31, 2024. Each subsequent Adjustment Period shall be the twelve months August 1 through July 31.

5. Authorized Base Revenues is the base revenues for a Customer Class as authorized by the Commission in the Company's most recent base rate case or other proceedings that result in an adjustment to base rates, or as adjusted by Commission order. This includes revenues authorized to be recovered through the Company's customer charge and distribution charges. This also includes any step revenue increases authorized by the Commission, but excludes revenues authorized to be recovered from the RDAF.

6. Authorized Base Revenues per Customer is the Authorized Base Revenues divided by the Authorized Number of Customers for a customer class.

7. Authorized Number of Customers is the number of customers in the test year for the applicable Customer Class as used in the rate design in the Company's most recent base rate case or as adjusted by Commission order.

8. Customer Class is the group of customers for purposes of calculating the Revenue Decoupling Adjustment amounts defined as follows: Domestic Delivery Service (Schedule D), Domestic Delivery Service (Schedule D-TOU), Regular General Service (Schedule G2), Regular General Service (Schedule G2 kWh meter), Regular General Service (Schedule G2 Quick Recovery Water Heating and Space Heating), and Large General Service (Schedule G1).

9. Measurement Period is the 12-month period in which the Company will measure variances between actual base revenues per customer and authorized base revenues per customer for each customer class. The first Measurement Period shall be the twelve-month period from April 1, 2022 to March 31, 2023. Each subsequent Measurement Period shall be the twelve months April 1 through March 31.

10. Revenue Decoupling Adjustment ("RDA") is the cumulative monthly revenue variances, carrying costs and reconciliation amount for the Measurement Period. The RDA forms the basis for RDAF.

5.0 CALCULATION OF REVENUE DECOUPLING ADJUSTMENT FACTOR

i. Description of RDAF Calculation

For each month within the Measurement Period, the Company shall calculate the variance between Actual Revenue per Customer and Authorized Revenue per Customer, for each Customer Class as defined in Section 4.0. The revenue per customer variance will be multiplied by the Actual Number of Customers per class, to determine the monthly Customer Class revenue variance. The revenue variance will be recorded in a deferral account with carrying costs accrued monthly at Prime rate with said Prime rate to be fixed on a quarterly basis and to be established as reported in THE WALL STREET JOURNAL on the first business day of the month preceding the calendar quarter. If more than one interest rate is reported, the average of the reported rates shall be used. On June 1 following the end of each Measurement Period, the Company will file for implementation of the RDAF, starting the first day of the Adjustment Period. The RDA at the end of Measurement Period will form the basis for the RDAF calculation. The RDA, including reconciliation amount and carrying costs, will be allocated to each customer class based upon the percentage of each class' Authorized Base Revenue, including step adjustments. The resulting class RDA will be divided by the class's projected sales for the adjustment period to determine the RDAF applicable to the given customer class.

ii. RDAF Calculation

1. Monthly Revenue Variance (MRV)

$$MRV_i^{CC} = \left(ARPC_i^{CC} - AURPC_i^{CC}\right) x\ ACUST_i^{CC}$$

Where:

$ACUST_i^{CC}$: Actual number of customers for month i for applicable Customer Class.

$ARPC_i^{CC}$: Actual Base Revenue Per Customer for month i for applicable Customer Class, derived as:

$$ARPC_i^{CC} = \frac{Actual\ Month\ i\ Revenue\ for\ Customer\ Class}{Actual\ Month\ i\ Bills\ for\ Customer\ Class}$$

$AURPC_i^{CG}$: Authorized Base Revenue Per Customer for month i for applicable Customer Class, derived as:

$$AURPC_i^{CC} = \frac{Authorized\ Month\ i\ Revenue\ for\ Customer\ Class}{Authorized\ Month\ i\ Bills\ for\ Customer\ Class}$$

CC: The six Customer Classes as defined in Section 4.0.

i: The twelve Months of the Measurement Period (April through March)

2. <u>Revenue Decoupling Adjustment (RDA)</u>

$$RDA\ = [\textstyle\sum_{CC=1}^{6}[\sum_{i=1}^{12} MRV_i^{CC} + CarryingCosts_i^{CC}\ ]] + REC_P$$

Where:

$CarryingCosts_i^{CC}$: Carrying Costs on the deferral account balance calculated at Prime rate for month i for applicable Customer Class.

REC_P: RDAC Reconciliation Balance from prior period p as defined in Section 7.0.

3. <u>RDA Allocation, subject to Adjustment Cap</u>

$IF: RDA < 0$
$AND\ IF: |RDA| > RDC$

$$THEN: RDA^{CC} = RDC\ \times \frac{AURV^{CC}}{\sum_{CC=1}^{CC=6}[AURV^{CC}]}$$

$$AND: REC_C = RDA - RDC$$

$$OTHERWISE: RDA^{CC} = RDA\ \times \frac{AURV^{CC}}{\sum_{CC=1}^{CC=6}[AURV^{CC}]}$$

Where:

$|RDA|$: Absolute Value of RDA

$AURV^{CC}$: Authorized Base Revenues for Customer Class

RDC: The Revenue Decoupling Cap that equals two and one half (2.5%) percent of total revenues from delivered sales for the most recent twelve-month period, April to March, as defined in Section 8.0 for the Adjustment Period. This cap is applicable to under recoveries only; over recoveries shall be credited in full.

REC_C: RDAC Reconciliation Balance for current period as defined in Section 7.0.

4. RDAF Calculation

$$RDAF^{CC} = -1 \times \frac{RDA^{CC}}{FS^{CC}}$$

Where:

FS^{CC}: The forecasted kWh Sales for the Adjustment Period for the applicable customer class

6.0 Application of the RDAF to Customer Bills

The RDAF ($ per kWh) shall be truncated at the nearest one one-thousandths of a cent per kWh. The RDAF will be applied to the monthly billed sales for each customer during the applicable Adjustment Period.

7.0 RDAC Reconciliation

The deferred balance shall contain the accumulated difference between the authorized RDA for the Adjustment Period determined in accordance with Section 4.0, and actual revenues received by the Company through application of the RDAF to customer bills in the Adjustment Period. Carrying costs shall be calculated on the average monthly balance of the deferred balance using the Prime rate.

8.0 Revenue Decoupling Adjustment Cap

The RDA for the Adjustment Period (determined in accordance with Section 5.0) may not exceed two and one half (2.5%) percent of total revenues from delivered sales for the most recent twelve-month period, April to March, with revenue for externally supplied customers being adjusted by imputing the Company's default service charges for that period. Total revenue shall include amounts that the Company has billed the Customer Classes as defined in Section 4.0 through applicable charges for distribution service, external delivery charge, stranded cost charge, storm recovery adjustment charge, system benefits charge, and any and all related adjustment factors. This cap is applicable to under recoveries only; over recoveries shall be credited in full. To the extent that the application of the RDA cap results in a RDA that is less than that calculated in accordance with Section 5.0, the difference shall be deferred and included in the RDAC Reconciliation for recovery in the subsequent Adjustment Period. Carrying costs shall be calculated on the average monthly balance using the Prime rate.

9.0 Information to be Filed with the Commission

Information pertaining to the RDAC will be filed annually on June 1 with the Commission consistent with the filing requirements of all costs and revenue information included in the Tariff. Such information shall include:

1. Calculation of monthly revenue variances for each Customer Class.

2. Determination of Revenue Decoupling Adjustment for the upcoming Adjustment Period.

3. Allocation of Revenue Decoupling Adjustment to each Customer Class.

4. Calculation of the Revenue Decoupling Adjustment Factors for each Customer Class, to be utilized in the upcoming Adjustment Period. If distribution rates change during the Measurement Period, the monthly revenue per customer for the remaining months of the Measurement Period will be revised and filed with the Commission.

[THIS PAGE INTENTIONALLY LEFT BLANK]

TABLE OF CONTENTS TO TARIFF NO. 3

~~This Schedule has been deleted.~~

A temporary rate distribution charge of $0.00501 per kilowatt hour shall be billed by the Company to all customers taking Delivery Service from the Company.

NHPUC No. 3 - Electricity Delivery
Unitil Energy Systems, Inc.

Forty-~~Fourth~~*Fifth* Revised Page 4
~~Issued in Lieu of~~ *Superseding* Forty-~~Third~~*Fourth* Revised Page 4

SUMMARY OF DELIVERY SERVICE RATES

Each bill rendered for electric delivery service shall be calculated through the application of the effective rates as listed below.

Class		~~Distribution Charge*~~	*Distribution Charge**	Non-Transmission External Delivery Charge**	Transmission External Delivery Charge**	Total External Delivery Charge**	Stranded Cost Charge**	Storm Recovery Adjustment Factor***	System Benefits Charge**** (1)	~~Total Delivery Charges~~	*Total Delivery Charges*
D	Customer Charge	~~$16.22~~	*$21.07*							~~$16.22~~	*$21.07*
	All kWh	~~$0.03558~~	*$0.04622*	($0.00019)	$0.03632	$0.03613	($0.00025)	$0.00084	$0.00752	~~$0.07982~~	*$0.09046*
G2	Customer Charge	~~$29.19~~	*$32.20*							~~$29.19~~	*$32.20*
	All kW	~~$10.51~~	*$11.59*				($0.05)			~~$10.46~~	*$11.54*
	All kWh	~~$0.00000~~	*$0.00000*	($0.00019)	$0.03632	$0.03613	($0.00005)	$0.00084	$0.00752	~~$0.04444~~	*$0.04444*
G2 - kWh meter	Customer Charge	~~$18.38~~	*$20.28*							~~$18.38~~	*$20.28*
	All kWh	~~$0.00883~~	*$0.00974*	($0.00019)	$0.03632	$0.03613	($0.00025)	$0.00084	$0.00752	~~$0.05307~~	*$0.05398*
G2 - Quick Recovery Water	Customer Charge	~~$9.73~~	*$10.73*							~~$9.73~~	*$10.73*
Heat and/or Space Heat	All kWh	~~$0.03204~~	*$0.03535*	($0.00019)	$0.03632	$0.03613	($0.00025)	$0.00084	$0.00752	~~$0.07628~~	*$0.07959*
G1	Customer Charge	~~$162.18~~	*$178.93*	Secondary Voltage						~~$162.18~~	*$178.93*
	Customer Charge	~~$86.49~~	*$95.42*	Primary Voltage						~~$86.49~~	*$95.42*
	All kVA	~~$7.60~~	*$8.37*				($0.06)			~~$7.54~~	*$8.31*
	All kWh	~~$0.00000~~	*$0.00000*	($0.00019)	$0.03632	$0.03613	($0.00006)	$0.00084	$0.00752	~~$0.04443~~	*$0.04443*
ALL GENERAL	Transformer Ownership Credit (kW/kVa)										($0.50)
	Voltage Discount at 4,160 Volts or Over (all kW/kVA and kWh)										2.00%
	Voltage Discount at 34,500 Volts or Over (all kW/kVA and kWh)										3.50%

(1) Includes low-income portion of $0.00150 per kWh, energy efficiency portion of $0.00528 per kWh and lost base revenue portion of $0.00074 per kWh.

** Authorized by NHPUC Order No. ~~26,236~~ __ in Case No. DE ~~19-043~~ __, dated ~~April 22, 2019~~ __*
*** Authorized by NHPUC Order No. 26,388 in Case No. DE 20-098, dated July 31, 2020*
**** Authorized by NHPUC Order No. 26,236 in Case No. DE 19-043, dated April 22, 2019*
***** Authorized by NHPUC Order No. 26,323 in Case No. DE 17-136, dated December 31, 2019*

Issued: ~~August 5, 2020~~*April 2, 2021*
Effective: ~~August 1, 2020~~*May 2, 2021*

Issued By: Robert B. Hevert
Sr. Vice President

SUMMARY OF DELIVERY SERVICE RATES (continued)

Class	Distribution Charge*	Non-Transmission External Delivery Charge**	Transmission External Delivery Charge**	External Delivery Charge**	Stranded Cost Charge**	Storm Recovery Adjustment Factor***	System Benefits Charge**** (1)	Total Delivery Charges
OL								
All kWh	$0.00000	($0.00019)	$0.03632	$0.03613	($0.00025)	$0.00084	$0.00752	$0.04424

Luminaire Charges

Category	Lamp Size Nominal Watts	Lumens (Approx.)	All-Night Service Monthly kWh	Midnight Service Monthly kWh	Description	*Price Per Luminaire* ~~Per Mo.~~	*Per Mo.*	Per Year	*Per Year*
Company	100	3,500	43	20	Mercury Vapor Street	~~$13.28~~	*$13.73*	$159.36	*$164.76*
Company	175	7,000	71	33	Mercury Vapor Street	~~$15.75~~	*$15.73*	$189.00	*$188.76*
Company	250	11,000	100	46	Mercury Vapor Street	~~$17.85~~	*$17.25*	$214.20	*$207.00*
Company	400	20,000	157	73	Mercury Vapor Street	~~$21.25~~	*$17.25*	$255.00	*$207.00*
Company	1,000	60,000	372	173	Mercury Vapor Street	~~$42.19~~	*$24.78*	$506.28	*$297.36*
Company	250	11,000	100	46	Mercury Vapor Flood	~~$19.02~~	*$18.25*	$228.24	*$219.00*
Company	400	20,000	157	73	Mercury Vapor Flood	~~$22.75~~	*$21.57*	$273.00	*$258.84*
Company	1,000	60,000	380	176	Mercury Vapor Flood	~~$37.70~~	*$25.29*	$452.40	*$303.48*
Company	100	3,500	48	22	Mercury Vapor Power Bracket	~~$13.41~~	*$13.44*	$160.92	*$161.28*
Company	175	7,000	71	33	Mercury Vapor Power Bracket	~~$14.87~~	*$14.65*	$178.44	*$175.80*
Company	50	4,000	23	11	Sodium Vapor Street	~~$13.52~~	*$13.73*	$162.24	*$164.76*
Company	100	9,500	48	22	Sodium Vapor Street	~~$15.22~~	*$15.73*	$182.64	*$188.76*
Company	150	16,000	65	30	Sodium Vapor Street	~~$15.28~~	*$17.25*	$183.36	*$207.00*
Company	250	30,000	102	47	Sodium Vapor Street	~~$19.14~~	*$19.53*	$229.68	*$234.36*
Company	400	50,000	161	75	Sodium Vapor Street	~~$24.13~~	*$24.78*	$289.56	*$297.36*
Company	1,000	140,000	380	176	Sodium Vapor Street	~~$41.66~~	*$42.51*	$499.92	*$510.12*
Company	150	16,000	65	30	Sodium Vapor Flood	~~$17.61~~	*$18.25*	$211.32	*$219.00*
Company	250	30,000	102	47	Sodium Vapor Flood	~~$20.76~~	*$21.57*	$249.12	*$258.84*
Company	400	50,000	161	75	Sodium Vapor Flood	~~$23.58~~	*$25.29*	$282.96	*$303.48*
Company	1,000	140,000	380	176	Sodium Vapor Flood	~~$42.03~~	*$42.89*	$504.36	*$514.68*
Company	50	4,000	23	11	Sodium Vapor Power Bracket	~~$12.51~~	*$13.44*	$150.12	*$161.28*
Company	100	9,500	48	22	Sodium Vapor Power Bracket	~~$14.04~~	*$14.65*	$168.48	*$175.80*
Company	175	8,800	74	34	Metal Halide Street	~~$19.91~~	*$17.25*	$238.92	*$207.00*
	~~250~~	~~13,500~~	~~102~~	~~47~~	~~Metal Halide Street~~	~~$21.65~~		~~$259.80~~	
	~~400~~	~~23,500~~	~~158~~	~~73~~	~~Metal Halide Street~~	~~$22.45~~		~~$269.40~~	
	~~175~~	~~8,800~~	~~74~~	~~34~~	~~Metal Halide Flood~~	~~$23.00~~		~~$276.00~~	
	~~250~~	~~13,500~~	~~102~~	~~47~~	~~Metal Halide Flood~~	~~$24.83~~		~~$297.96~~	
	~~400~~	~~23,500~~	~~158~~	~~73~~	~~Metal Halide Flood~~	~~$24.88~~		~~$298.56~~	
Company	1,000	86,000	374	174	Metal Halide Flood	~~$32.22~~	*$25.29*	$386.64	*$303.48*
	~~175~~	~~8,800~~	~~74~~	~~34~~	~~Metal Halide Power Bracket~~	~~$18.63~~		~~$223.56~~	
	~~250~~	~~13,500~~	~~102~~	~~47~~	~~Metal Halide Power Bracket~~	~~$19.81~~		~~$237.72~~	
	~~400~~	~~23,500~~	~~158~~	~~73~~	~~Metal Halide Power Bracket~~	~~$21.17~~		~~$254.04~~	
Company	~~42~~*35*	~~3,600~~*3,000*	~~15~~*12*	~~7~~*6*	LED Area Light Fixture	~~$13.16~~	*$13.44*	~~$157.92~~	*$161.28*
Company	~~57~~*47*	~~5,200~~*4,000*	~~20~~*16*	~~9~~*8*	LED Area Light Fixture	~~$13.21~~	*$14.65*	~~$158.52~~	*$175.80*
Company	~~25~~*30*	~~3,000~~*3,300*	~~9~~*10*	~~4~~*5*	LED ~~Cobra Head~~*Street Light* Fixture	~~$13.11~~	*$13.73*	~~$157.32~~	*$164.76*
Company	~~88~~*50*	~~8,300~~*5,000*	~~30~~*17*	~~14~~*8*	LED ~~Cobra Head~~*Street Light* Fixture	~~$13.30~~	*$15.73*	~~$159.60~~	*$188.76*
Company	~~108~~*100*	~~11,500~~*11,000*	~~37~~*35*	~~17~~*17*	LED ~~Cobra Head~~*Street Light* Fixture	~~$13.36~~	*$17.25*	~~$160.32~~	*$207.00*
Company	*120*	*18,000*	*42*	*19*	*LED Street Light Fixture*		*$19.53*		*$234.36*
Company	~~193~~*140*	~~21,000~~*18,000*	~~67~~*48*	~~31~~*23*	LED ~~Cobra Head~~*Street Light* Fixture	~~$13.62~~	*$24.78*	~~$163.44~~	*$297.36*
Company	*260*	*31,000*	*90*	*42*	*LED Street Light Fixture*		*$42.51*		*$510.12*
Company	~~123~~*70*	~~12,180~~*10,000*	~~43~~*24*	~~20~~*12*	LED Flood Light Fixture	~~$13.41~~	*$18.25*	~~$160.92~~	*$219.00*
Company	*90*	*10,000*	*31*	*14*	*LED Flood Light Fixture*		*$21.57*		*$258.84*
Company	~~194~~*110*	~~25,700~~*15,000*	~~67~~*38*	~~31~~*18*	LED Flood Light Fixture	~~$13.62~~	*$25.29*	~~$163.44~~	*$303.48*
Company	~~297~~*370*	~~38,100~~*46,000*	~~103~~*128*	~~48~~*61*	LED Flood Light Fixture	~~$13.93~~	*$42.89*	~~$167.16~~	*$514.68*
Customer Paid	*35*	*3,000*	*12*	*6*	*LED Area Light Fixture*		*$7.00*		*$84.00*
Customer Paid	*47*	*4,000*	*16*	*8*	*LED Area Light Fixture*		*$8.21*		*$98.52*
Customer Paid	*30*	*3,300*	*10*	*5*	*LED Street Light Fixture*		*$9.71*		*$116.52*
Customer Paid	*50*	*5,000*	*17*	*8*	*LED Street Light Fixture*		*$11.92*		*$143.04*
Customer Paid	*100*	*11,000*	*35*	*17*	*LED Street Light Fixture*		*$12.48*		*$149.76*
Customer Paid	*120*	*18,000*	*42*	*19*	*LED Street Light Fixture*		*$14.76*		*$177.12*
Customer Paid	*140*	*18,000*	*48*	*23*	*LED Street Light Fixture*		*$17.83*		*$213.96*
Customer Paid	*260*	*31,000*	*90*	*42*	*LED Street Light Fixture*		*$33.56*		*$402.72*
Customer Paid	*70*	*10,000*	*24*	*12*	*LED Flood Light Fixture*		*$11.24*		*$134.88*
Customer Paid	*90*	*10,000*	*31*	*14*	*LED Flood Light Fixture*		*$14.56*		*$174.72*
Customer Paid	*110*	*15,000*	*38*	*18*	*LED Flood Light Fixture*		*$17.36*		*$208.32*
Customer Paid	*370*	*46,000*	*128*	*61*	*LED Flood Light Fixture*		*$27.00*		*$324.00*

(1) Includes low-income portion of $0.00150 per kWh, energy efficiency portion of $0.00528 per kWh and lost base revenue portion of $0.00074 per kWh.

** Authorized by NHPUC Order No. ~~26,236~~ __ in Case No. DE ~~19-043~~ __, dated ~~April 22, 2019~~ __*
*** Authorized by NHPUC Order No. 26,388 in Case No. DE 20-098, dated July 31, 2020*
**** Authorized by NHPUC Order No. 26,236 in Case No. DE 19-043, dated April 22, 2019*
***** Authorized by NHPUC Order No. 26,323 in Case No. DE 17-136, dated December 31, 2019*

NHPUC No. 3 - Electricity Delivery
Unitil Energy Systems, Inc.

~~Sixty-Fifth~~*Sixth* Revised Page 6
Superseding ~~Sixty-Fourth~~*Fifth* Revised Page 6

SUMMARY OF LOW-INCOME
ELECTRIC ASSISTANCE PROGRAM DISCOUNTS

Low-Income Electric Assistance Program (LI-EAP) Discounts for Eligible Customers

				~~**LI-EAP discount Delivery Only; Excludes Supply**~~	***LI-EAP discount Delivery Only; Excludes Supply***	**LI-EAP discount Fixed Default Service Supply Only**	**LI-EAP discount Variable Default Service Supply Only**					
Tier	Percentage of NH State Median Income & Federal Poverty Guidelines	Discount (5)	Blocks	~~Dec 2020-May 2021 (1)~~	*May 2, 2021 (1)*	Dec 2020-May 2021 (2)	Dec-20 (3)	Jan-21 (3)	Feb-21 (3)	Mar-21 (3)	Apr-21 (3)	May-21 (3)
1 (4)	N/A	N/A										
2	151 (FPG) - 60 (SMI)	8%	Customer Charge	~~($1.30)~~	*($1.69)*							
			First 750 kWh	~~($0.00639)~~	*($0.00724)*	($0.00745)	($0.00721)	($0.00857)	($0.00870)	($0.00707)	($0.00645)	($0.00599)
			Excess 750 kWh	~~$0.00000~~	*$0.00000*	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
3	126 (FPG) - 150 (FPG)	22%	Customer Charge	~~($3.57)~~	*($4.64)*							
			First 750 kWh	~~($0.01756)~~	*($0.01990)*	($0.02049)	($0.01982)	($0.02356)	($0.02393)	($0.01945)	($0.01773)	($0.01646)
			Excess 750 kWh	~~$0.00000~~	*$0.00000*	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
4	101 (FPG) - 125 (FPG)	36%	Customer Charge	~~($5.84)~~	*($7.59)*							
			First 750 kWh	~~($0.02874)~~	*($0.03257)*	($0.03353)	($0.03243)	($0.03856)	($0.03916)	($0.03183)	($0.02902)	($0.02694)
			Excess 750 kWh	~~$0.00000~~	*$0.00000*	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
5	76 (FPG) - 100 (FPG)	52%	Customer Charge	~~($8.43)~~	*($10.96)*							
			First 750 kWh	~~($0.04151)~~	*($0.04704)*	($0.04844)	($0.04684)	($0.05570)	($0.05657)	($0.04598)	($0.04191)	($0.03892)
			Excess 750 kWh	~~$0.00000~~	*$0.00000*	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
6	0 - 75 (FPG)	76%	Customer Charge	~~($12.33)~~	*($16.01)*							
			First 750 kWh	~~($0.06066)~~	*($0.06875)*	($0.07079)	($0.06845)	($0.08140)	($0.08267)	($0.06720)	($0.06126)	($0.05688)
			Excess 750 kWh	~~$0.00000~~	*$0.00000*	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000

(1) Discount calculated using total utility charges from Page 4 multiplied by the appropriate discount. These figures exclude default service and are applicable to customers choosing a Competitive Supplier or self-supply. Customers taking default service from the Company would receive these discounts plus the appropriate discount applicable to default service supply. Competitively supplied customers billed on a consolidated basis would receive these discounts plus the appropriate fixed default service supply discount.

(2) Discount calculated using Non-G1 class (Residential) Fixed Default Service Rate multiplied by the appropriate discount. These figures exclude delivery.

(3) Discount calculated using Non-G1 class (Residential) Variable Default Service Rate, for the applicable month, multiplied by the appropriate discount. These figures exclude delivery.

(4) Tier 1 was eliminated by Order No. 25,200 in DE 10-192 dated March 4, 2011.

(5) Discounts effective July 1, 2016 in accordance with Order No. 25-901 in DE 14-078.

Authorized by NHPUC Order No. ~~26,414~~ __ in Case No. DE ~~20-039~~ __ , dated ~~October 6, 2020~~ __

Issued: ~~September 25, 2020~~*April 2, 2021*
Effective: ~~December 1, 2020~~*May 2, 2021*

Issued By: Robert B. Hevert
Sr. Vice President

L. "Payment Agent" shall mean any third-party authorized by a Customer to receive and pay the bills rendered by the Company for service under this Tariff.

M. "Rate Schedule" shall mean the Rate Schedules included as part of this Tariff.

N. "Tariff" shall mean this Delivery Service Tariff and all Rate Schedules, appendices and exhibits to such Tariff.

O. "Terms and Conditions" shall mean these Terms and Conditions for Distribution Service.

II. DISTRIBUTION SERVICES

1. Rates and Tariffs

A. Schedule of Rates

The Company furnishes its various services under tariffs and/or contracts ("Schedule of Rates") promulgated in accordance with the provisions of the applicable rules of the New Hampshire Public Utilities Commission and the laws of the State of New Hampshire. Such Schedule of Rates, which includes these Terms and Conditions for Distribution Service, is available for public inspection during normal business hours at the business offices of the Company, on Unitil.com, and at the offices of the Commission.

B. Amendments; Conflicts

The Schedule of Rates may be revised, amended, supplemented or supplanted in whole or in part from time to time according to the procedures provided by Commission rules and regulations. When effective, all such revisions, amendments, supplements, or replacements will appropriately supersede the existing Schedule of Rates. If there is a conflict between the express terms of any Rate Schedule or contract approved by the Commission and these Terms and Conditions, the express terms of the Rate Schedule or contract shall govern.

C. Modification by Company

No agent or employee of the Company is authorized to modify any provision or rate contained in the Schedule of Rates or to bind the Company to perform in any manner contrary thereto. Any modification to the Schedule of Rates or any promise contrary thereto shall be in writing, duly executed by an authorized officer of the Company, subject in all cases to applicable statutes and to the orders and regulations of the Commission, and available for public inspection during normal business hours at the business offices of the Company and at the offices of the Commission.

(10) Selection of Supplier by a Customer:

Any Customer requesting or receiving Delivery Service under this Tariff is responsible for selecting or changing a Supplier. The Company shall process a change in or initiation of Generation Service within two business days of receiving a valid Electronic Enrollment from a Supplier. The Supplier must satisfy all the applicable requirements of this Tariff and the Commission's rules prior to the commencement of Generation Service. The date of change in, or initiation of, Generation Service shall commence upon the next meter reading date for the customer provided the Company receives and successfully processes the Electronic Enrollment at least two business days prior to the regularly scheduled meter reading cycle date for the Customer.

(11) Termination of Generation Service

To terminate Generation Service from a particular Supplier, a Customer may either have the Supplier of record send to the Company a "Supplier Drops Customer" transaction, in accordance with the Terms and Conditions for Energy Service Providers section of this Tariff, or request Generation Service from an alternative Supplier. Generation Service from the Supplier of record shall terminate on the next meter read date provided the Company has received either a valid "Supplier Drops Customer" notice from the Supplier of record or a valid Electronic Enrollment from a new Supplier at least two business days prior to the regularly scheduled meter read date.

E. Term of Customer's Obligation to Company

Each Customer shall be liable for service taken until such time as the Customer requests termination of Distribution Service and a final meter reading is recorded by the Company. The bill rendered by the Company based on such final meter reading shall be payable upon receipt. In the event that the Customer of Record hinders the Company's access to the meter or fails to give notice of termination of Distribution Service to the Company, the Customer of Record shall continue to be liable for service provided until the Company either disconnects the meter or a new party becomes a Customer of the Company at such service location. The Customer shall be liable for all costs incurred by the Company when the Customer prevents access to the Company's equipment. If the customer is a tenant, they will need to contact their landlord to provide access. If the landlord refuses~~,~~ pursuant to NHPUC 1203.10(c) the landlord will be responsible for all charges from the date of notice given by the customer or the date that the meter is disconnected or a new tenant takes over service whichever is first.

3. Security Deposits

A. Non-Residential Accounts

To protect against loss, or before rendering or restoring service under Section 6, the Company will require a deposit from all non-residential Customers in accordance with NHPUC 1203.03. The maximum amount of any security deposit required shall not exceed two times the average monthly bill ~~the estimated charge for Distribution Service for a period of two (2) high use months (the highest use month will not be used to determine the amount of the deposit)~~ or $10.00, whichever is greater. ~~For Customers who are receiving Default Service, the estimated charge for a period of two (2) high use months for these services will~~

~~be added to the estimated charge for Distribution Service as determined above, when calculating the amount of the security deposit required.~~ The Company may refuse to render service to all non-residential Customers for failure to make a deposit, in accordance with NHPUC 1203.03.

B. Residential Accounts

(1) New Residential Service: Pursuant to the provisions of NHPUC 1203.03(a), the Company may require a security deposit on a new residential account when:

~~Service will be temporary, seasonal or transient, however, if the Customer has not been delinquent in his accounts for Distribution Service for a period of six (6) months, no deposit may be required.~~

(a) When t~~T~~he Customer has an undisputed overdue balance, incurred within the last three (3) years, on a prior ~~Distribution Service account which remains unpaid within thirty (30) days prior to application for a similar type of service~~account with the utility or any similar type of utility.

(b) When any ~~distribution company~~utility has successfully obtained a judgment against the Customer during the past two (2) years for non-payment of a delinquent account for utility service.

(c) When ~~any similar type~~the utility has disconnected the Customer's service within the last three (3) years because the Customer interfered with, or diverted, the service of the utility~~company~~ situated on or about the Customer's premises.

(d) When the customer is unable to provide satisfactory evidence to the utility that he or she intends to remain at the location for which service is being requested for a period of 12 consecutive months, unless he or she provides satisfactory evidence that he or she has not been delinquent in his or her similar utility service accounts for a period of 12 months, in which case no deposit shall be required.

(2) Existing Residential Service: Pursuant to the provisions of NHPUC 1203.03(e), the Company may require a deposit on an existing residential account when:

(a) The Customer has received four (4) disconnect notices for non-payment within a twelve (12) month period.

(b) The service has been disconnected for non-payment or a delinquent account.

(c) The Customer interfered with or diverted the service of the Company situated on or delivered on or about the Customer's premises.

(d) The Customer has filed for bankruptcy and included the Company as a creditor under the filing and the filing has been accepted. Any such deposit requirement shall be in accordance with 11 U.S.C. §366.

(3) If the Company requires a security deposit, the Company shall inform the Customer, orally and in writing, of the option to provide a third party guarantee in lieu of a deposit pursuant to the provisions of NHPUC 1203.03.

(4) The Company shall not require a residential deposit or furnish a guarantee as a condition of new or continued service based on the customer's income, home

ownership, residential location, race, color, creed, sex, gender identity, sexual orientation, marital status, age with the exception of unemancipated minors, national origin, or disability and shall make such requirement only in accordance with NHPUC 1203.03.

(5) The Company may refuse to render service to any residential Customers for failure to make a deposit, in accordance NHPUC 1203.03.

C. Termination of Service

The Company may terminate a Customer's Distribution Service if a security deposit, authorized by Sections 3.A and 3.B, above, is not made in accordance with the provisions outlined in NHPUC 1203.03 and 1204.00.

D. Refund of Deposit; Interest

Interest shall be paid on cash deposits from the date of deposit at the rate prescribed by the New Hampshire Public Utilities Commission. When a deposit has been held longer than twelve (12) months, interest shall be paid to the Customer or credited to the Customer's current bill not less than annually. Deposits plus accrued interest thereon, less any amount due the Company, will be refunded within sixty (60) days of termination of service or when satisfactory credit relations have been established over at least twelve (12) consecutive months for a residential Customer and twenty-four (24) consecutive months for a non-residential Customer.

4. Service Supplied

A. Customer Delivery Point and Metering Installation

(1) Except as noted herein, the Company shall furnish and install, at locations it designates, one or more meters for the purpose of measuring the electricity delivered. The Company may at any time change any meter it installed. Except as specifically provided by a given rate, all rates in the Schedule of Rates are predicated on service to a Customer at a single Customer Delivery Point and metering installation. Where service is supplied to an account at more than one delivery point or metering installation, each single point of delivery or metering installation shall be considered to be a separate account for purposes of applying the Schedule of Rates, except (a) if a Customer is served through multiple Customer Delivery Points or metering installations for the Company's own convenience; or (b) if otherwise approved by the Commission, or (c) if the Customer applies to the Company and the use is found to comply with the availability clauses in the Schedule of Rates.

(2) Any new or renovated domestic structure with more than one (1) dwelling unit will be metered separately and each meter will be billed as an individual Customer (NHRSA 155.D and Section 505.1 NH Energy Code). Where a business enterprise, occupation or institution occupies more than one unit or space, each unit or space will be metered separately and considered a distinct Customer, unless the Customer furnishes, owns, and maintains the necessary distribution circuits by which to connect the units.

5. Billing and Metering

A. Billing Period Defined

The basis of all charges is the billing period, defined as the time period between two consecutive regular monthly meter readings or estimates of such monthly meter readings. The standard billing period is thirty (30) days. Bills for Distribution Service will be rendered monthly.

B. Bills; Time of Payment

Unless otherwise specified, bills of the Company are payable upon receipt and may be paid online at Unitil.com, via the automated phone system, with a Customer Service Representative or with ~~at~~ any ~~business office of the Company or at any~~ authorized collector or agent. Bills shall be deemed paid when valid payment is received by the Company.~~at any of these identified payment locations.~~ Bills shall be deemed rendered and other notices duly given when delivered personally to the Customer or three (3) days following the date of mailing to the mailing address, or to the premises supplied, or the last known address of the Customer. The telephone number of the Company's Customer Service Center ~~or Competitive Supplier if applicable~~ shall appear on each residential bill rendered by the Company. A statement that customers should call the NHPUC's Consumers Affairs Division for further assistance after first attempting to resolve any dispute with the Company or Competitive Supplier should also be included on each residential bill. Customer payment responsibilities with Competitive Suppliers shall be governed by the particular Customer/Competitive Supplier contract.

C. Past Due Bills

Unless otherwise stated in a Rate Schedule, each bill for Distribution Service shall be due by the date included on the bill, generally twenty-five (25) days from the bill date, ~~postmarked on the bill~~. Bills paid after the due date will be subject to interest charges in accordance with NHPUC 1203.08 and Section 5.E below.

D. Failure of Payment Agent to Remit Payment

A customer who has elected to use a Payment Agent shall be treated in the same manner as other Customers in the Company's application of the applicable statues, rules and regulations of the Commission and the terms and conditions of this Tariff, notwithstanding any failure of the Payment Agent to remit payment to the Company. ~~or any failure of the Payment Agent to forward to the Customer any Company notices, bill inserts or other written correspondence.~~ The Customer shall be solely responsible for all amounts due, including, but not limited to, any late payment charges.

E. Interest on Past Due Accounts

Unless otherwise stated in a Rate Schedule, bills for which valid payment has not been received within twenty-five (25) days from the ~~postmark~~ bill date shall be considered past due and accrue interest on any unpaid balance, including any outstanding interest charges.

Such interest rate shall be determined in accordance with NHPUC 1203.08. Such interest charge shall be paid from the date thereof until the date of payment.

F. Billing for Generation Service

The Company shall provide a single bill, reflecting unbundled charges for electric service, to Customers who receive Default Service.

The Company shall offer two billing service options to Competitive Suppliers providing Generation Service to Customers: A) Standard Bill Service; and B) Consolidated Bill Service, as set forth in the Terms and Conditions for Competitive Suppliers, Section III.6.A. and III.6.B. The Competitive Supplier shall inform the Distribution Company of the selected billing option, in accordance with the rules and procedures set forth in the EDI Working Group Report.

G. Generation Source

The Company shall reasonably accommodate a change from Default Service or Generation Service to a new Competitive Supplier in accordance with the rules as developed by the EDI working group.

H. Actual Meter Readings; Estimates

The Company shall make an actual meter reading at least every third billing period. If a meter is not scheduled to be read in a particular month, or if the Company is unable to read the meter when scheduled, or if the meter for any reason fails to register the correct amount of electricity supplied or the correct demand of any Customer for a period of time, the Company shall make a reasonable estimate of the consumption of electricity during those months when the meter is not read or is not registering properly, based on available data, and such estimated bills shall be payable as rendered.

I. Optional Customer Meter Readings

Any Customer who would otherwise receive an estimated bill pursuant to Section 5.H, above, may elect to receive a bill based on a Customer meter reading by reading his/her meter on the date prescribed by the Company.~~, and completing and returning a postcard, furnished by the Company, within the prescribed time.~~

J. Constant Use Installation

The Company may calculate rather than meter the kilowatt demand and kilowatt-hours used by any installation for which the demand and hours-use are definitely known.

K. Determination of Customer's Demand

Where a rate requires determination of maximum demand, it shall be determined by measurement or estimated as provided by the rate or where applicable by the provisions of the following paragraphs of this section.

(1) When measured, the demand shall be based upon the greatest rate of taking service during a fifteen (15) minute interval except that it may be based upon a shorter interval when of an instantaneous or widely fluctuating character.

(2) When the nature of the load served is of an intermittent, instantaneous or widely fluctuating character such as to render demand meter readings of doubtful value as compared to the actual capacity requirements, the demand may be determined on the basis of a time interval less than that specified, or on the basis of the minimum transformer capacity necessary to render the service, or the minimum load limiting device rating necessary to permit continuous uninterrupted service. In all such instances, the Company will document the basis of demand determination.

L. Access to Meters

A properly identified and authorized representative of the Company shall have the right to gain access at all reasonable times and intervals for the purpose of reading, installing, examining, testing, repairing, replacing, or removing the Company's meters, meter reading devices, wires, or other electrical equipment and appliances, or of discontinuing service, in accordance with the applicable laws of the State of New Hampshire, rules and regulations of the Commission, and Company policy in effect from time to time, and the Customer or Landlord/Owner of the building shall not prevent or hinder the Company's access.

M. Diversion and Meter Tampering

If a Customer receives unmetered service as the result of any tampering with the meter or other Company equipment, the Company shall take appropriate corrective action including, but not limited to, making changes in the meter or other equipment and rebilling the Customer. The Customer may be held responsible to the Company for the receipt of Distribution Service not registered on the meter.

N. Returned Check Fee

The Company may assess a returned check fee pursuant to Section 10, below, to any Customer whose check made payable to the Company is dishonored by any bank when presented for payment by the Company. Receipt of a check or payment instrument that is subsequently dishonored shall not be considered valid payment.

O. Collection of Taxes

The Company shall collect all sales, excise, or other taxes imposed by governmental authorities with respect to the delivery of electricity. The Customer shall be responsible for identifying and requesting any exemption from the collection of the tax by filing appropriate documentation with the Company.

(1) *Simultaneous purchase and sale* is an arrangement whereby a QF's entire output is considered to be sold to the utility, while power used internally by the QF is considered to be simultaneously purchased from the Company through Default Service or from a Competitive Supplier.

(2) *Net purchases or sale* is an arrangement whereby output of a QF is considered to be used to the extent needed for the QF's internal needs, while any additional power needed by the QF is purchased from the Company through Default Service or from a Competitive Supplier, or any surplus power generated by the QF is sold to the Company as surplus.

(3) *Internal use only* is an arrangement whereby output of the QF is used entirely for internal needs. The Customer's meter is ~~dentated~~detented, to stop the meter from going backwards in case of any inadvertent flow into the Company's System.

G. Inspection of Customer's Premises

The Company reserves the right to make an inspection of the Customer's premises before rendering service in order to see that its rules are complied with. Neither by inspection or non-rejection of service, nor in any other way, does the Company give any warranty, express or implied, as to the adequacy, safety or other characteristics of any structures, equipment, wiring, appliances or devices which utilize electricity and are owned, installed or maintained by the Customer or leased by the Customer from third parties.

8. Company's Installation

A. Information and Requirements for Distribution Service

Upon request, the Company shall furnish to any person detailed information on the method and manner of making service connections. Such detailed information may include a copy of the Company's Information and Requirements Booklet, a description of the service available, connections necessary between the Company's facilities and the Customer's premises, location of entrance facilities and metering equipment, and Customer and Company responsibilities for installation of facilities.

B. Interference with Company Property

All meters, services, and other electric equipment owned by the Company, regardless of location, shall be and will remain the property of the Company; and no one other than an employee or authorized agent of the Company shall be permitted to remove, operate, or maintain such property. The Customer shall not interfere with or alter the meter, seals or other property used in connection with the rendering of service or permit the same to be done by any person other than the authorized agents or employees of the Company. The Customer shall be responsible for all damage to or loss of such property unless occasioned by circumstances beyond the Customer's control. Such property shall be installed at points most convenient for the Company's access and service and in conformance with public regulations in force from time to time. The costs of relocating such property shall be borne by the Customer when done at the Customer's request, for

(2) Access to Company Equipment: The Company shall have free and safe access to its equipment located on the Customer's premises at all times, including but not limited to subsurface structures, above ground enclosures, and pad mounted equipment, and the Customer shall authorize and/or obtain his landlord's permission for such access. If the Company is denied free access to said property, the equipment shall be relocated or removed at the Customer's expense. Ornamental shrubs and/or other types of vegetation may be removed by the Company in order to access its equipment, and such removal shall be done at the customer's expense. The Customer shall not knowingly permit access to Company's equipment except by authorized employees of the Company.

9. Company Liability

A. Emergency Interruption of Service

Whenever the Company reasonably believes the integrity of the Company's system or the supply of electricity to be threatened by conditions on its system or upon the systems with which it is directly or indirectly interconnected, the Company, may in the exercise of reasonable judgment, curtail or interrupt electric service or reduce voltage, and such action shall not be construed to constitute a default nor shall the Company be liable therefor in any respect. The Company will use reasonable efforts under the circumstances to overcome the cause of such curtailment, interruption, or reduction and to resume full performance.

B. Planned Interruption of Service

The Company may, in the exercise of reasonable judgment, curtail or interrupt electric service or reduce voltage for the purposes of planned maintenance, installation or replacement. When such curtailment is necessary, the Company shall conduct such work at a time causing the minimum inconvenience to customers consistent with the circumstances. The Company shall, if practical, notify customers in advance that might be seriously ~~effected~~ affected by interruptions to service. The Company will provide notice to any customer of whom it is previously aware who would encounter a potentially life-threatening situation as a result of the planned interruptions. A potentially life-threatening situation for this purpose shall include life support equipment or other potentially life-threatening medical situations. Such action shall not be construed to constitute a default nor shall the Company be liable therefor in any respect.

C. Non-Performance Due to Force Majeure

The Company shall be excused from performing under the Schedule of Rates and shall not be liable in damages or otherwise if and to the extent that it shall be unable to do so or prevented from doing so by statute or regulation or by action of any court or public authority having or purporting to have jurisdiction in the premises, or by loss, diminution, or impairment of electrical service from its generating plants or suppliers or the systems of others with which it is interconnected, or by a break or fault in its transmission or distribution system; failure or improper operation of transformers, switches, or other equipment necessary for electric distribution, or by reason of storm, flood, fire, earthquake, explosion, civil disturbance, labor difficulty, act of God, or public enemy,

CHARACTER OF SERVICE

Electricity will normally be delivered at 120/240 volts using three wire, single phase service. In some areas service may be 120/208 volts, ~~single phase,~~ three wire, single phase.

DELIVERY SERVICE CHARGES - MONTHLY

The Delivery Service Charges shall include Distribution Charges and Adjustments, set forth below. The Distribution Charges are subject to annual adjustment as approved in DE ~~16-384~~21-030.

DISTRIBUTION CHARGES - MONTHLY

Customer Charge:	$~~16.22~~21.07 per meter
Distribution Charge:	~~3.558~~4.622¢ per kWh

MINIMUM CHARGE

The minimum charge per month, or fraction thereof, shall be the Customer Charge.

ADJUSTMENTS

These Adjustments, included in the Delivery Service Charges, shall be adjusted from time to time.

External Delivery Charge: All energy delivered under this Schedule shall be subject to the External Delivery Charge as provided in Schedule EDC of the Tariff of which this is a part.

Stranded Cost Charge: All energy delivered under this Schedule shall be subject to the Stranded Cost Charge as provided in Schedule SCC of the Tariff of which this is a part.

Storm Recovery Adjustment Factor: All energy delivered under this Schedule shall be subject to the Storm Recovery Adjustment Factor as provided in Schedule SRAF of the Tariff of which this is a part.

System Benefits Charge: All energy delivered under this Schedule shall be subject to the System Benefits Charge as provided in Schedule SBC of the Tariff of which this is a part.

Revenue Decoupling Adjustment Charge: All energy delivered under this Schedule shall be subject to the Revenue Decoupling Adjustment Charge as provided in Schedule RDAC of the Tariff of which this is a part.

Default Service Charge: For Customers receiving Default Service from the Company, all energy delivered under this Schedule shall be subject to the Default Service Charge as provided in Schedule DS of the Tariff of which this is a part.

LOW INCOME ENERGY ASSISTANCE PROGRAM

Customers taking service under this rate may be eligible to receive discounts under the statewide low-income electric assistance program (“LI-EAP”) authorized by the New Hampshire Public Utilities Commission. Eligibility for the LI-EAP shall be determined by the Community Action Agencies. Customers participating in the LI-EAP will continue to take service under this rate, but will receive a discount as provided under this Tariff as applicable.

AVAILABILITY

Service is available under this Schedule to non-domestic Customers for all general purposes and includes the operation of single phase motors having such characteristics and so operated as not to impair service to other Customers. Single phase motors exceeding five (5) horsepower will be allowed only upon approval by the Company in each instance. Unmetered traffic and flashing signal lights existing immediately prior to the effective date of this Schedule shall also be billed under this Schedule.

This Schedule is for delivery service only. Customers are required to obtain an energy supply from a Competitive Supplier, self-supply (available to Market Participant End Users as described in NHPUC Order No. 24,172), or may be eligible for Default Service from the Company pursuant to Schedule DS as amended from time to time.

CHARACTER OF SERVICE

Electric service of the following description is available, depending upon the location of the Customer: (1) 120/240 volts, single phase, three wire; (2) 120/208 volts, single phase, three wire; (3) 208Y/120 volts, three phase, four wire; (4) 480Y/277 volts, three phase, four wire; (5) 4160 volts, three phase, four wire or such higher primary distribution voltage as may be available, the voltage to be designated by the Company.

DELIVERY SERVICE CHARGES – MONTHLY

The Delivery Service Charges shall include Distribution Charges and Adjustments, set forth below. The Distribution Charges are subject to annual adjustment as approved in DE ~~16-384~~21-030.

Large General Service Schedule G1: for any industrial or commercial Customer with its average use consistently equal to or in excess of two hundred (200) kilovolt-amperes of demand and/or generally greater than or equal to one-hundred thousand (100,000) kilowatt-hours per month.

DISTRIBUTION CHARGES - MONTHLY

Customer Charge:	Secondary Voltage	$~~162.18~~178.93 per meter
	Primary Voltage	$~~86.49~~95.42 per meter
Distribution Charges:	$~~7.60~~8.37 per kVA	
	0.000¢ per kWh	

Regular General Service Schedule G2: for any industrial or commercial Customer with its average use consistently below two-hundred (200) kilovolt-amperes of demand and/or generally less than one-hundred thousand (100,000) kilowatt-hours per month.

DISTRIBUTION CHARGES - MONTHLY

Customer Charge:	$~~29.19~~32.20 per meter
Distribution Charges:	$~~10.51~~11.59 per kW 0.000¢ per kWh

Regular General Service Schedule G2 kWh meter: Service is available under this Schedule only to Customers at locations which were receiving service under Unitil Energy Systems, Inc.'s NHPUC No. 1 and are presently receiving service under this Schedule. New Customers at existing locations and new locations shall not be eligible for this rate, but the Company will install a demand meter and the location shall be served under Schedule G2. Customers who have installed distributed generation shall not be eligible for this rate but shall be served under Schedule G2.

DISTRIBUTION CHARGES - MONTHLY

Customer Charge:	$~~18.38~~20.28 per meter
Distribution Charge:	~~0.883~~0.974¢ per kWh

Uncontrolled (Quick Recovery) Water Heating: Uncontrolled (Quick Recovery) Water Heating is available under this Schedule at those locations which were receiving uncontrolled (Quick Recovery) water heating service under Unitil Energy Systems, Inc.'s NHPUC No. 1 and are presently receiving service under this Schedule.

For those locations which qualify under the preceding paragraph, uncontrolled quick recovery water heating service is available under this Schedule if the Customer has installed and in regular operation throughout the entire year an electric water heater of the quick recovery type, equipped with two thermostatically operated heating elements, each with a rating of no more than 4,500 watts, so connected and interlocked that they cannot operate simultaneously and if the water heater supplies the Customer's entire water heating requirements, all electricity supplied thereto under this provision will be metered separately and billed as follows:

DISTRIBUTION CHARGES - MONTHLY

Customer Charge:	$~~9.73~~10.73 per meter
Distribution Charge:	~~3.204~~3.535¢ per kWh

Space Heating: Space Heating is available under this Schedule at those locations which were receiving space heating service under Unitil Energy Systems, Inc.'s NHPUC No. 1 and are presently receiving service under this Schedule. Customers who qualify for service under this Schedule for five (5) kilowatts or more of permanently-installed space heating equipment under this provision may elect to have such service metered separately and billed as follows:

DISTRIBUTION CHARGES - MONTHLY

Customer Charge:	$~~9.73~~10.73 per meter
Distribution Charge:	~~3.204~~3.535¢ per kWh

DETERMINATION OF DEMAND

Large General Service Schedule G1

For the purpose of demand billing under the Large General Service Schedule G1, metered demands shall be measured as the highest 15-minute integrated kilovolt-ampere (kVA) demand determined during the current month for which the bill is rendered. The monthly billing demand charge shall be based upon this metered demand except that it shall not be less than 80% of the highest demand in any of the immediately preceding eleven months, and in no event shall such demand be taken or considered as being less than 50 kVA.

Regular General Service Schedule G2

The metered demand used for billing shall be the maximum fifteen-minute kilowatt (kW) demand determined during the current month, but in no case less than one kW or the minimum available demand capacity specified by an agreement between the Customer and the Company. The billing demand shall be taken in 0.1 kW intervals, and those demands falling between the intervals shall be billed on the next lower 0.1 kW.

If the Customer's average use is consistently equal to or in excess of two-hundred (200) kilovolt-ampere (kVA) of demand and/or is generally greater than one-hundred thousand (100,000) kilowatt-hours per month, as measured by the Company, the Customer may be placed on rate
G1.

The Company reserves the right to install kilovolt-ampere meters, and in such case the monthly demand shall not be less than 90% of the measured kVA.

METERING

The Company may at its option meter at the Customer's utilization voltage or on the high tension side of the transformer through which service is furnished.

In the latter case, or if the Customer's utilization voltage requires no transformation, and if the Company meters service at 4,160 volts or over, a compensating deduction of 2.0% will be made from the metered kilowatt or kilovolt-ampere demand and metered kilowatt-hour usage to determine billing amounts. If the Company meters service at 34,500 volts or over, a compensating deduction of 3.5% will be made from the metered kilowatt or kilovolt-ampere demand and metered kilowatt-hour usage to determine billing amounts. Demands for these purposes will be as determined under the Determination of Demand provision of this Schedule.

CREDIT FOR TRANSFORMER OWNERSHIP

If the Customer furnishes all transformers which may be required so that the Company is not required to furnish any transformers, there will be credited, against the amount established under the Determination of Demand and Metering provisions of this Schedule, 50 cents for each kilowatt of monthly billing demand, or 50 cents for each kilovolt-ampere of monthly billing demand.

MINIMUM CHARGE

The Minimum Charge per month or fraction thereof will be as follows:

Large General Service Schedule G1:

The Minimum Charge per month shall be no less than the Customer Charge for each type of service installed plus a capacity charge based upon a minimum demand and/or demand ratchet as defined under the Determination of Demand provision of this Schedule.

Regular General Service Rates G2:

The Minimum Charge per month shall be no less than the Customer Charge for each type of service installed plus a capacity charge based upon a minimum demand as defined under the Determination of Demand provision of this Schedule.

G2 kWh meter, Uncontrolled (Quick Recovery) Water Heating, and Space Heating:

The Minimum Charge per month shall be the Customer Charge for each type of service installed.

ADJUSTMENTS

These Adjustments, included in the Delivery Service Charges, shall be adjusted from time to time.

External Delivery Charge: All energy delivered under this Schedule shall be subject to the External Delivery Charge as provided in Schedule EDC of the Tariff of which this is a part.

Stranded Cost Charge: All energy delivered under this Schedule shall be subject to the Stranded Cost Charge as provided in Schedule SCC of the Tariff of which this is a part.

Storm Recovery Adjustment Factor: All energy delivered under this Schedule shall be subject to the Storm Recovery Adjustment Factor as provided in Schedule SRAF of the Tariff of which this is a part.

System Benefits Charge: All energy delivered under this Schedule shall be subject to the System Benefits Charge as provided in Schedule SBC of the Tariff of which this is a part.

Revenue Decoupling Adjustment Charge: All energy delivered under this Schedule shall be subject to the Revenue Decoupling Adjustment Charge as provided in Schedule RDAC of the Tariff of which this is a part.

Default Service Charge: For Customers receiving Default Service from the Company, all energy delivered under this Schedule shall be subject to the Default Service Charge as provided in Schedule DS of the Tariff of which this is a part.

determined be less than a) the capacity installed by the Company on a network system, ~~or~~b) 80% of the kilovolt-ampere rating of the transformers installed for supplying service to the Customer, or c) 80% of the Customer's total electrical requirements, as determined by the Company.

(d) Minimum Charge

An amount equal to the total of the Customer Charge and the Distribution Demand Charge as provided for Customers taking standard delivery service under this Schedule.

(e) Parallel Operation

The Customer shall at no time operate any other source of electricity supply in parallel with the service furnished by the Company except with the written consent of the Company.

(f) Term of Contract

The initial term of service hereunder shall not be less than five years unless the Customer discontinues Customer's other source of electrical power and takes all Customer's delivery service requirements from the Company.

(g) Auxiliary Energy Supply

Energy supply for Auxiliary Service is available from the Company via Default Service pursuant to Schedule DS as amended from time to time, and may be available from Competitive Suppliers.

(h) Special Provision

If the Customer is supplied from transformers also supplying other Customers, the Company may require the Customer to install a service or main switch or circuit breaker as specified by the Company.

TARIFF PROVISIONS

The Company's complete Tariff where not inconsistent with any specific provisions hereof, is a part of this rate.

AVAILABILITY

This Schedule is available to governmental bodies and private Customers for unmetered outdoor lighting service supplied from the Company's existing overhead conductors with lighting fixtures mounted on existing poles. Mercury Vapor lighting fixtures will be unavailable at new locations after December 1, 2002. Starting January 1, 2023, the Company will no longer offer sodium vapor and metal halide luminaires. From that date on, as these legacy fixtures need replacement, they will be replaced with light emitting diode ("LED") fixtures, and there will be no special charges to the customer for this replacement. If, however, a customer requests a conversion of a legacy fixture, or multiple fixtures, to LED service in advance of its actual need, requirement for replacement, or Company planned servicing, the Company may require the customer to pay all or a portion of the costs of the conversions as specified under SPECIAL PROVISIONS parts d. and e. below. Conversions are also contingent upon the availability of Company personnel and/or other resources necessary to perform the conversion.

This Schedule is for delivery service only. Customers are required to obtain an energy supply from a Competitive Supplier, self-supply (available to Market Participant End Users as described in NHPUC Order No. 24,172), or may be eligible for Default Service from the Company pursuant to Schedule DS as amended from time to time.

LIMITATIONS ON AVAILABILITY

The availability of this rate to any Customer is contingent upon the availability to the Company of personnel and/or other resources necessary to perform the conversion of existing fixtures in accordance with the time schedule specified in the Service Agreement.

CHARACTER OF SERVICE

All lighting shall be photoelectrically controlled. The Company will furnish and maintain the equipment hereinafter described and shall supply service at which the lamps are designed to operate. All lighting fixtures will be group relamped in accordance with the lamp manufacturer's suggested schedule. At relamping time the fixture will be maintained in accordance with the fixture manufacturer's suggested procedures.

DELIVERY SERVICE CHARGES – MONTHLY

The Delivery Service Charges shall include Distribution Charges and Adjustments, set forth below. The Distribution Charges are subject to annual adjustment as approved in DE ~~16-384~~21-030.

DISTRIBUTION CHARGES: LUMINAIRE – MONTHLY

Distribution Charge: 0.000¢ per kWh

Lamp Size Nominal Watts	Lumens Approx.	Description of Luminaire	Luminaire Price per Month	All-Night Service Option Luminaire Monthly kWh	Midnight Service Option Luminaire Monthly kWh
100	3,500	Mercury Vapor Street	$~~13.28~~13.73	43	20
175	7,000	Mercury Vapor Street	$~~15.75~~15.73	71	33
250	11,000	Mercury Vapor Street	$~~17.85~~17.25	100	46
400	20,000	Mercury Vapor Street	$~~21.25~~17.25	157	73
1,000*	60,000	Mercury Vapor Street	$~~42.19~~24.78	372	173
250	11,000	Mercury Vapor Flood	$~~19.02~~18.25	100	46
400	20,000	Mercury Vapor Flood	$~~22.75~~21.57	157	73
1,000	60,000	Mercury Vapor Flood	$~~37.70~~25.29	380	176
100	3,500	Mercury Vapor Power Bracket	$~~13.41~~13.44	48	22
175	7,000	Mercury Vapor Power Bracket	$~~14.87~~14.65	71	33
50	4,000	Sodium Vapor Street	$~~13.52~~13.73	23	11
100	9,500	Sodium Vapor Street	$~~15.22~~15.73	48	22
150	16,000	Sodium Vapor Street	$~~15.28~~17.25	65	30
250	30,000	Sodium Vapor Street	$~~19.14~~19.53	102	47

~~DISTRIBUTION CHARGES: LUMINAIRE – MONTHLY (cont.)~~

~~Lamp Size Nominal Watts~~	~~Lumens Approx.~~	~~Description of Luminaire~~	~~Luminaire Price per Month~~	~~All-Night Service Option Luminaire Monthly kWh~~	~~Midnight Service Option Luminaire Monthly kWh~~
400	50,000	Sodium Vapor Street	$~~24.13~~24.78	161	75
1,000*	140,000	Sodium Vapor Street	$~~41.66~~42.51	380	176
150	16,000	Sodium Vapor Flood	$~~17.61~~18.25	65	30
250	30,000	Sodium Vapor Flood	$~~20.76~~21.57	102	47
400	50,000	Sodium Vapor Flood	$~~23.58~~25.29	161	75
1,000	140,000	Sodium Vapor Flood	$~~42.03~~42.89	380	176
50	4,000	Sodium Vapor Power Bracket	$~~12.51~~13.44	23	11
100	9,500	Sodium Vapor Power Bracket	$~~14.04~~14.65	48	22
175	8,800	Metal Halide Street	$~~19.91~~17.25	74	34
~~250~~	~~13,500~~	~~Metal Halide Street~~	~~$21.65~~	~~102~~	~~47~~
~~400~~	~~23,500~~	~~Metal Halide Street~~	~~$22.45~~	~~158~~	~~73~~
~~175~~	~~8,800~~	~~Metal Halide Flood~~	~~$23.00~~	~~74~~	~~34~~
~~250~~	~~13,500~~	~~Metal Halide Flood~~	~~$24.83~~	~~102~~	~~47~~
~~400~~	~~23,500~~	~~Metal Halide Flood~~	~~$24.88~~	~~158~~	~~73~~
1,000	86,000	Metal Halide Flood	$~~32.22~~25.29	374	174
~~175~~	~~8,800~~	~~Metal Halide Power Bracket~~	~~$18.63~~	~~74~~	~~34~~
~~250~~	~~13,500~~	~~Metal Halide Power Bracket~~	~~$19.81~~	~~102~~	~~47~~
~~400~~	~~23,500~~	~~Metal Halide Power Bracket~~	~~$21.17~~	~~158~~	~~73~~
35	3,000	LED Area Light Fixture	$13.44	12	6
47	4,000	LED Area Light Fixture	$14.65	16	8
30	3,300	LED Street Fixture	$13.73	10	5
50	5,000	LED Street Fixture	$15.73	17	8
100	11,000	LED Street Fixture	$17.25	35	16
120	18,000	LED Street Fixture	$19.53	42	19
140	18,000	LED Street Fixture	$24.78	48	23
260	31,000	LED Street Fixture	$42.51	90	42
70	10,000	LED Flood Light Fixture	$18.25	24	11

90	10,000	LED Flood Light Fixture	$21.57	31	14
110	15,000	LED Flood Light Fixture	$25.29	38	18
370	46,000	LED Flood Light Fixture	$42.89	128	60

* 1,000 Watt Mercury Vapor Street and 1,000 Watt Sodium Vapor Street are no longer available. Flood lights are available with brackets and ballasts as specified by the Company.

The prices and monthly kWh specified in this table for LED fixtures will apply to luminaires +/- 5 watts above or below the stated wattage in accordance with ANSI C136-15-2020 to accommodate the evolution of LED lighting fixtures.

MONTHLY KWH PER LUMINAIRE

For billing purposes on Energy based charges and adjustments, the monthly kWh figures shown in the table above under Distribution Charges - Monthly: Luminaire shall be used for each luminaire and service option type.

OTHER FIXTURES AND EQUIPMENT

Lighting fixtures other than that specified herein will be provided only at prices and for a contract term to be mutually agreed upon between the Company and the Customer.

MINIMUM CHARGE

The minimum charge per month, or fraction thereof, per lamp shall be the Distribution Charge: Luminaire.

ADJUSTMENTS

These Adjustments, included in the Delivery Service Charges, shall be adjusted from time to time.

External Delivery Charge: All energy delivered under this Schedule shall be subject to the External Delivery Charge as provided in Schedule EDC of the Tariff of which this is a part.

Stranded Cost Charge: All energy delivered under this Schedule shall be subject to the Stranded Cost Charge as provided in Schedule SCC of the Tariff of which this is a part.

Storm Recovery Adjustment Factor: All energy delivered under this Schedule shall be subject to the Storm Recovery Adjustment Factor as provided in Schedule SRAF of the Tariff of which this is a part.

System Benefits Charge: All energy delivered under this Schedule shall be subject to the System Benefits Charge as provided in Schedule SBC of the Tariff of which this is a part.

Revenue Decoupling Adjustment Charge: All energy delivered under this Schedule shall be subject to the Revenue Decoupling Adjustment Charge as provided in Schedule RDAC of the Tariff of which this is a part.

Default Service Charge: For Customers receiving Default Service from the Company, all energy delivered under this Schedule shall be subject to the Default Service Charge as provided in Schedule DS of the Tariff of which this is a part.

TERMS OF PAYMENT

The charges for service hereunder are net, billed monthly and due within 25 days following the date postmarked on the bill, as specified in the Terms and Conditions for Distribution Service, which is a part of this Tariff.

TERM OF CONTRACT

Except as provided in the Special Provisions section, service under this Schedule shall be for an initial period of one year with automatic one year extensions thereafter until cancelled by either the Customer or the Company giving to the other notice in writing at least 30 days in advance.

SPECIAL PROVISIONS

(a) Hours of Operation

Approximate hours of operation under the all-night service option will be from one-quarter hour after sunset to one-quarter hour before sunrise. Annual burn hours of 4150 are estimated for billing kWh purposes for the all-night service option. Approximate hours of operation under the midnight service option will be from one-quarter hour after sunset to midnight. Annual burn hours of 1,930 are estimated for billing kWh purposes for the midnight service option.

(b) Lamp Replacement

The Company shall replace defective lamps as promptly as possible during regular working hours, after having been advised as to the need of such replacement by the Customer.

(c) Change of Location

The Company will, at the expense to the Customer, change the location of such fixtures as the Customer may order.

(d) Change/Removal of Fixture

The Company will change the type of lighting fixture at the Customer's request, but may require the Customer to reimburse the Company for all or part of the depreciated cost of the retired equipment including installation and cost of removal, less any salvage value thereon.

(e) Conversion to LED~~HPS or Metal Halide~~

If a Customer requests multiple conversions of fixtures from Mercury Vapor to LED~~High Pressure Sodium, Mercury Vapor to Metal Halide~~, or from High Pressure Sodium to LED~~Metal Halide~~, the Company may, in addition to the provisions of section (d) above, require the Customer to pay all or a portion of the costs of the conversions, including labor, material, traffic control, and overheads. Conversions to High Pressure Sodium or Metal Halide are no longer offered.

Lamp Size				All-Night Service	Midnight Service
Nominal Watts	Lumens Approx.	Description of Luminaire	Luminaire Price per Month	Option Luminaire Monthly kWh	Option Luminaire Monthly kWh
~~42~~35	~~3,600~~3,000	LED Area Light Fixture	$~~13.16~~7.00	~~15~~12	~~7~~6
~~57~~47	~~5,200~~4,000	LED Area Light Fixture	$~~13.21~~8.21	~~20~~16	~~9~~8
~~25~~30	~~3,000~~3,300	LED ~~Cobra Head~~Street Fixture	$~~13.11~~9.71	~~9~~10	~~4~~5
~~88~~50	~~8,300~~5,000	LED ~~Cobra Head~~Street Fixture	$~~13.30~~11.92	~~30~~17	~~14~~8
~~108~~100	~~11,500~~11,000	LED ~~Cobra Head~~Street Fixture	$~~13.36~~12.48	~~37~~35	~~17~~16
120	18,000	LED Street Fixture	$14.76	42	19
~~193~~140	~~21,000~~18,000	LED ~~Cobra Head~~Street Fixture	$~~13.62~~17.83	~~67~~48	~~31~~23
260	31,000	LED Street Fixture	$33.56	90	42
~~123~~70	~~12,180~~10,000	LED Flood Light Fixture	$~~13.41~~11.24	~~43~~24	~~20~~11
90	10,000	LED Flood Light Fixture	$14.56	31	14
~~194~~110	~~25,700~~15,000	LED Flood Light Fixture	$~~13.62~~17.36	~~67~~38	~~31~~18
~~297~~370	~~38,100~~46,000	LED Flood Light Fixture	$~~13.93~~27.00	~~103~~128	~~48~~60

The prices and monthly kWh specified in this table for LED fixtures will apply to luminaires +/- 5 watts above or below the stated wattage in accordance with ANSI C136-15-2020 to accommodate the evolution of LED lighting fixtures.

MONTHLY KWH PER LUMINAIRE

For billing purposes on Energy based charges and adjustments, the monthly kWh figures shown in the table above under Distribution Charges - Monthly: Luminaire shall be used for each luminaire and service option type.

OTHER LED FIXTURES AND LED EQUIPMENT

Lighting fixtures other than that specified herein will be provided only at prices and for a contract term to be mutually agreed upon between the Company and the Customer.

MINIMUM CHARGE

The minimum charge per month, or fraction thereof, per lamp shall be the Distribution Charge: Luminaire.

ADJUSTMENTS

These Adjustments, included in the Delivery Service Charges, shall be adjusted from time to time.

External Delivery Charge: All energy delivered under this Schedule shall be subject to the External Delivery Charge as provided in Schedule EDC of the Tariff of which this is a part.

Stranded Cost Charge: All energy delivered under this Schedule shall be subject to the Stranded Cost Charge as provided in Schedule SCC of the Tariff of which this is a part.

Storm Recovery Adjustment Factor: All energy delivered under this Schedule shall be subject to the Storm Recovery Adjustment Factor as provided in Schedule SRAF of the Tariff of which this is a part.

System Benefits Charge: All energy delivered under this Schedule shall be subject to the System Benefits Charge as provided in Schedule SBC of the Tariff of which this is a part.

Revenue Decoupling Adjustment Charge: All energy delivered under this Schedule shall be subject to the Revenue Decoupling Adjustment Charge as provided in Schedule RDAC of the Tariff of which this is a part.

Default Service Charge: For Customers receiving Default Service from the Company, all energy delivered under this Schedule shall be subject to the Default Service Charge as provided in Schedule DS of the Tariff of which this is a part.

TERMS OF PAYMENT

The charges for service hereunder are net, billed monthly and due within 25 days following the date postmarked on the bill, as specified in the Terms and Conditions for Distribution Service, which is a part of this Tariff.

TERM OF CONTRACT

Except as provided in the Special Provisions section, service under this Schedule shall be for an initial period of one year with automatic one year extensions thereafter until cancelled by either the Customer or the Company giving to the other notice in writing at least 30 days in advance.

MAINTENANCE

The Company shall exercise reasonable diligence to insure that all lamps are burning and shall make replacements promptly when notified of outages. However, the Company shall not be required to perform any replacements or maintenance except during regular working hours.
The Company will be responsible for correcting UES system voltage problems at no charge to the Customer. When the Company responds to a report of a non-working fixture not related to voltage, the Customer will be assessed a per-fixture per-visit charge to replace photoelectric

The External Delivery Charge ("EDC"), as specified on Calculation of the External Delivery Charge, shall be billed by the Company to all customers taking Delivery Service from the Company. The purpose of the EDC is to recover, on a fully reconciling basis, the costs billed to the Company by Other Transmission Providers as well as third party costs billed to the Company for energy and transmission related services and other costs approved by the Commission as specified herein.

The EDC shall include the following charges, except that third party costs associated with Default Service shall be included in the Default Service Charge: 1) charges billed to the Company by Other Transmission Providers as well as any charges relating to the stability of the transmission system which the Company is authorized to recover by order of the regulatory agency having jurisdiction over such charges, 2) transmission-based assessments or fees billed by or through regulatory agencies, 3) costs billed by third parties for load estimation and reconciliation and data and information services necessary for allocation and reporting of supplier loads, and for reporting to, and receiving data from, ISO New England, 4) legal and consulting outside service charges related to the Company's transmission and energy obligations and responsibilities, including legal and regulatory activities associated with the independent system operator ("ISO"), New England Power Pool ("NEPOOL"), regional transmission organization ("RTO") and Federal Energy Regulatory Commission ("FERC"), and Commission approved special assessments charged to the Company due to the expenses of experts employed by the Office of Consumer Advocate pursuant to the provisions of RSA 363:28,III. 5) the costs of Administrative Service Charges billed to the Company by Unitil Power Corp. under the FERC-approved Amended Unitil System Agreement, 6) Effective July 1, 2014, in accordance with RSA 363-A:6, amounts above or below the total NHPUC Assessment, less amounts charged to base distribution and Default Service, and 7) cash working capital associated with Other Flow-Through Operating Expenses. In addition, the EDC shall include the calendar year over- or under-collection from the Company's Vegetation Management Program and Reliability Enhancement Program. The over- or under- collection shall be credited or charged to the EDC on May 1 of the following year, or, with approval of the Commission, the Company may credit unspent amounts to future Vegetation Management Program expenditures. ~~The EDC shall include rate case expenses and other regulatory expenses allowed by the Commission in Docket DE 16-384.~~

Also, as approved in Docket DE 21-030, the EDC shall include the over- or under-collection of the following costs compared to the level included in distribution rates: (1) delivery write offs, (2) Arrearage Management Program costs, (3) waived late payment fee charges, and (4) wheeling revenue. The over- or under- collection shall be credited or charged to the EDC on May 1 of the following year. In addition, the EDC shall recover (1) deferred Calypso storm charges, (2) Electric Vehicle ("EV") rebate costs, and (3) EV and Time of Use marketing, communications, and education plan costs. The EDC shall also include a charge for the recovery of displaced distribution revenue associated with net metering ~~for~~ from 2013 until such time as the Company implements decoupling~~and subsequent years~~. Lastly, the EDC shall include the prudently incurred costs, as approved by the Commission, associated with the alternative net metering tariff approved in Docket DE 16-576, including: net metering credits; meters installed and related data management; independent monitoring services, bi-directional and production meters installed and related data management systems and processes; pilot programs; studies; and data collection, maintenance and dissemination. For purposes of this Schedule, "Other Transmission Provider" shall be defined as any transmission provider and other regional transmission and/or operating entities, such as NEPOOL, a regional transmission group ~~("RTG")~~, an ISO, and their successors, or other such body with the oversight of regional transmission, in the event that any of these entities are authorized to bill the Company directly for their services.

The EDC shall be established annually based on a forecast of includable costs, and shall also include a full reconciliation with interest for any over- or under-recoveries occurring in prior year(s). Interest shall be calculated at the prime rate, with said prime rate to be fixed on a quarterly basis and to be established as reported in THE WALL STREET JOURNAL on the first business day of the month preceding the calendar quarter. If more than one interest rate is reported, the average of the reported rates shall be used. The Company may file to change the EDC at any time should significant over- or under-recoveries occur or be expected to occur. In addition, the Company's annual filing shall breakdown the EDC into two components (transmission and non-transmission) for purposes of billing under the alternative net metering tariff that became effective September 1, 2017.

Any adjustment to the EDC shall be in accordance with a notice filed with the Commission setting forth the amount of the proposed charge and the amount of the increase or decrease. The notice shall further specify the effective date of such charge, which shall not be earlier than forty-five days after the filing of the notice, or such other date as the Commission may authorize. The annual adjustment to the EDC shall be derived in the same manner as that provided by Calculation of the External Delivery Charge.

~~*Authorized by NHPUC Order No. 26,388 in Case No. DE 20-098, dated July 31, 2020*~~

1.0 PURPOSE

The purpose of the Revenue Decoupling Adjustment Clause ("RDAC") is to establish procedures that allow the Company to adjust, on an annual basis, rates for distribution service that reconcile Actual Base Revenues per Customer with Authorized Base Revenues per Customer.

2.0 EFFECTIVE DATE

The Revenue Decoupling Adjustment Factor ("RDAF") shall be effective on the first day of the Adjustment Period, as defined in Section 4.0.

3.0 APPLICABILITY

The RDAF shall apply to the Company's Domestic Delivery Service (Schedule D), Domestic Delivery Service (Schedule D-TOU) and General Delivery Service (Schedule G), as determined in accordance with the provisions of this Tariff.

4.0 DEFINITIONS

The following definitions shall apply throughout the Tariff:

1. Actual Base Revenues is the revenue collected for a Customer Class through the Company's customer charge and distribution charges. This excludes revenues collected through the RDAF.

2. Actual Number of Customers is the number of customers for the applicable customer class. Actual Number of Customers shall be based on the monthly equivalent bills for a customer class.

3. Actual Base Revenues per Customer is Actual Base Revenues divided by the Actual Number of Customers for a Customer Class.

4. Adjustment Period is the 12-month period for which the RDAF will be applied for each applicable customer class. The first Adjustment Period shall be the twelve-month period from August 1, 2023 to July 31, 2024. Each subsequent Adjustment Period shall be the twelve months August 1 through July 31.

5. Authorized Base Revenues is the base revenues for a Customer Class as authorized by the Commission in the Company's most recent base rate case or other proceedings that result in an adjustment to base rates, or as adjusted by Commission order. This includes revenues authorized to be recovered through the Company's customer charge and distribution charges. This also includes any step revenue increases authorized by the Commission, but excludes revenues authorized to be recovered from the RDAF.

6. Authorized Base Revenues per Customer is the Authorized Base Revenues divided by the Authorized Number of Customers for a customer class.

7. Authorized Number of Customers is the number of customers in the test year for the applicable Customer Class as used in the rate design in the Company's most recent base rate case or as adjusted by Commission order.

8. Customer Class is the group of customers for purposes of calculating the Revenue Decoupling Adjustment amounts defined as follows: Domestic Delivery Service (Schedule D), Domestic Delivery Service (Schedule D-TOU), Regular General Service (Schedule G2), Regular General Service (Schedule G2 kWh meter), Regular General Service (Schedule G2 Quick Recovery Water Heating and Space Heating), and Large General Service (Schedule G1).

9. Measurement Period is the 12-month period in which the Company will measure variances between actual base revenues per customer and authorized base revenues per customer for each customer class. The first Measurement Period shall be the twelve-month period from April 1, 2022 to March 31, 2023. Each subsequent Measurement Period shall be the twelve months April 1 through March 31.

10. Revenue Decoupling Adjustment ("RDA") is the cumulative monthly revenue variances, carrying costs and reconciliation amount for the Measurement Period. The RDA forms the basis for RDAF.

5.0 CALCULATION OF REVENUE DECOUPLING ADJUSTMENT FACTOR

i. Description of RDAF Calculation

For each month within the Measurement Period, the Company shall calculate the variance between Actual Revenue per Customer and Authorized Revenue per Customer, for each Customer Class as defined in Section 4.0. The revenue per customer variance will be multiplied by the Actual Number of Customers per class, to determine the monthly Customer Class revenue variance. The revenue variance will be recorded in a deferral account with carrying costs accrued monthly at Prime rate with said Prime rate to be fixed on a quarterly basis and to be established as reported in THE WALL STREET JOURNAL on the first business day of the month preceding the calendar quarter. If more than one interest rate is reported, the average of the reported rates shall be used. On June 1 following the end of each Measurement Period, the Company will file for implementation of the RDAF, starting the first day of the Adjustment Period. The RDA at the end of Measurement Period will form the basis for the RDAF calculation. The RDA, including reconciliation amount and carrying costs, will be allocated to each customer class based upon the percentage of each class' Authorized Base Revenue, including step adjustments. The resulting class RDA will be divided by the class's projected sales for the adjustment period to determine the RDAF applicable to the given customer class.

ii. RDAF Calculation

1. <u>Monthly Revenue Variance (MRV)</u>

$$MRV_i^{CC} = \left(ARPC_i^{CC} - AURPC_i^{CC}\right) x \; ACUST_i^{CC}$$

Where:

$ACUST_i^{CC}$: Actual number of customers for month i for applicable Customer Class.

$ARPC_i^{CC}$: Actual Base Revenue Per Customer for month i for applicable Customer Class, derived as:

$$ARPC_i^{CC} = \frac{Actual\ Month\ i\ Revenue\ for\ Customer\ Class}{Actual\ Month\ i\ Bills\ for\ Customer\ Class}$$

$AURPC_i^{CG}$: Authorized Base Revenue Per Customer for month i for applicable Customer Class, derived as:

$$AURPC_i^{CC} = \frac{Authorized\ Month\ i\ Revenue\ for\ Customer\ Class}{Authorized\ Month\ i\ Bills\ for\ Customer\ Class}$$

CC: The six Customer Classes as defined in Section 4.0.

i: The twelve Months of the Measurement Period (April through March)

2. Revenue Decoupling Adjustment (RDA)

$$RDA\ = [\sum_{CC=1}^{6}[\sum_{i=1}^{12} MRV_i^{CC} + CarryingCosts_i^{CC}\ ]] + REC_P$$

Where:

$CarryingCosts_i^{CC}$: Carrying Costs on the deferral account balance calculated at Prime rate for month i for applicable Customer Class.

REC_P: RDAC Reconciliation Balance from prior period p as defined in Section 7.0.

3. RDA Allocation, subject to Adjustment Cap

$IF: RDA < 0$
$AND\ IF: |RDA| > RDC$

$$THEN: RDA^{CC} = RDC\ \times \frac{AURV^{CC}}{\sum_{CC=1}^{CC=6}[AURV^{CC}]}$$

$$AND: REC_C = RDA - RDC$$

$$OTHERWISE: RDA^{CC} = RDA\ \times \frac{AURV^{CC}}{\sum_{CC=1}^{CC=6}[AURV^{CC}]}$$

Where:

$|RDA|$: Absolute Value of RDA

$AURV^{CC}$: Authorized Base Revenues for Customer Class

RDC: The Revenue Decoupling Cap that equals two and one half (2.5%) percent of total revenues from delivered sales for the most recent twelve-month period, April to March, as defined in Section 8.0 for the Adjustment Period. This cap is applicable to under recoveries only; over recoveries shall be credited in full.

REC_C: RDAC Reconciliation Balance for current period as defined in Section 7.0.

4. RDAF Calculation

$$RDAF^{CC} = -1 \times \frac{RDA^{CC}}{FS^{CC}}$$

Where:

FS^{CC}: The forecasted kWh Sales for the Adjustment Period for the applicable customer class

6.0 Application of the RDAF to Customer Bills

The RDAF ($ per kWh) shall be truncated at the nearest one one-thousandths of a cent per kWh. The RDAF will be applied to the monthly billed sales for each customer during the applicable Adjustment Period.

7.0 RDAC Reconciliation

The deferred balance shall contain the accumulated difference between the authorized RDA for the Adjustment Period determined in accordance with Section 4.0, and actual revenues received by the Company through application of the RDAF to customer bills in the Adjustment Period. Carrying costs shall be calculated on the average monthly balance of the deferred balance using the Prime rate.

8.0 Revenue Decoupling Adjustment Cap

The RDA for the Adjustment Period (determined in accordance with Section 5.0) may not exceed two and one half (2.5%) percent of total revenues from delivered sales for the most recent twelve-month period, April to March, with revenue for externally supplied customers being adjusted by imputing the Company's default service charges for that period. Total revenue shall include amounts that the Company has billed the Customer Classes as defined in Section 4.0 through applicable charges for distribution service, external delivery charge, stranded cost charge, storm recovery adjustment charge, system benefits charge, and any and all related adjustment factors. This cap is applicable to under recoveries only; over recoveries shall be credited in full. To the extent that the application of the RDA cap results in a RDA that is less than that calculated in accordance with Section 5.0, the difference shall be deferred and included in the RDAC Reconciliation for recovery in the subsequent Adjustment Period. Carrying costs shall be calculated on the average monthly balance using the Prime rate.

9.0 Information to be Filed with the Commission

Information pertaining to the RDAC will be filed annually on June 1 with the Commission consistent with the filing requirements of all costs and revenue information included in the Tariff. Such information shall include:

1. Calculation of monthly revenue variances for each Customer Class.

2. Determination of Revenue Decoupling Adjustment for the upcoming Adjustment Period.

3. Allocation of Revenue Decoupling Adjustment to each Customer Class.

4. Calculation of the Revenue Decoupling Adjustment Factors for each Customer Class, to be utilized in the upcoming Adjustment Period. If distribution rates change during the Measurement Period, the monthly revenue per customer for the remaining months of the Measurement Period will be revised and filed with the Commission.

[THIS PAGE INTENTIONALLY LEFT BLANK]

State of New Hampshire
Public Utilities Commission
Concord

Report of Proposed Rate Changes
($000)

Unitil Energy Systems, Inc.
Tariff No. 3

Date Filed: April 2, 2021
Effective Date: May 2, 2021

(A) Class of Service	(B) Effect of Proposed Change	(C) Average Number of Customers	(D) Total Revenue Under Present Rates	(E) Proposed Distribution Change	(F) Change in Reconciling Mechanism Revenue	(G) Total Revenue Under Proposed Rates	(H) Proposed Change Revenue	(I) Percent Change Revenue
Domestic D	Increase	67,940	$102,471	$9,445	-$1,175	$110,741	$8,270	8.1%
General Service - G2	Increase	10,559	$57,627	$1,715	-$711	$58,631	$1,004	1.7%
G2 - kWh Meter	Increase	379	$145	$9	-$1	$153	$8	5.5%
G2 - Quick Recovery Water Heat and/or Space Heat	Increase	257	$763	$18	-$10	$771	$8	1.0%
Subtotal G2	Increase	11,195	$58,535	$1,742	-$722	$59,555	$1,020	1.7%
Large General Service G1	Increase	168	$49,323	$801	-$728	$49,395	$73	0.1%
Outdoor Lighting OL	Increase	1,549	$2,816	$0	-$17	$2,799	($17)	(0.6%)
Total	Increase	80,852	$213,145	$11,989	-$2,643	$222,491	$9,346	4.4%

(D) Present rates including delivery and default service rates effective December 1, 2020. Assumes all customers take default energy service.
G1 default service rate of $0.08581 (avg Dec '20 - Apr '21) used for G1.
(E) Total amount differs from revenue deficiency in RevReq-1 by $3k due to rounding.
(F) Class proportion of proposed changes in EDC and SBC.
(G) Column D + Column E + Column F.
(H) Column G - Column D
(I) Column H / Column D

Signed by: ___ /s/ Robert B Hevert
Title: Sr. Vice President

[THIS PAGE INTENTIONALLY LEFT BLANK]

UNITIL ENERGY SYSTEMS, INC.
DE 21-030

Statement to Customers
Pursuant to PUC 1203.02(c)

On April 2, 2021, Unitil Energy Systems, Inc. ("Unitil") filed with the New Hampshire Public Utilities Commission a proposed increase of approximately 4.4% over the Company's total revenue under present rates. The proposed increase is designed to provide additional revenues in support of the Company's distribution investments and operations. As part of its filing, the Company is requesting a temporary increase of 2.7% to become effective this summer while the Commission reviews Unitil's request. Both requests require Commission review and approval in a proceeding that may last up to a year or more, and the approved increases may be different from what has been requested. Additional information about Unitil's requested delivery rate increases is available below and on the NHPUC's website at:
https://www.puc.nh.gov/Regulatory/Docketbk/2021/21-030.html

The proposed effects of Unitil's requested changes to rates are shown below. The actual effects of the rate changes will be determined by the Public Utilities Commission.

DOMESTIC DELIVERY SERVICE CUSTOMERS (SCHEDULE D)
Based on Unitil's requested temporary rate increase, residential customers would see an average increase of 2.5% this summer. The projected average increase in monthly bills at the conclusion of the rate proceeding for residential customers on Default Service would be 8.1%.

GENERAL DELIVERY SERVICE CUSTOMERS (SCHEDULE G – G2; G2 KWH METER; AND UNCONTROLLED WATER HEATING/SPACE HEATING)
The monthly bill impact for a regular general customer will vary based upon demand. Unitil's requested temporary rate increase would result in an average increase in monthly bills of approximately 2.7% this summer. The projected average increase in monthly bills at the conclusion of the rate proceeding for regular general customers on Default Service would be approximately 1.7%.

GENERAL DELIVERY SERVICE CUSTOMERS (SCHEDULE G - G1 LARGE)
The monthly bill impact for a large general customer will vary based upon demand. Unitil's requested temporary rate increase would result in an average increase in monthly bills of approximately 3.2% this summer. The projected average increase in monthly bills at the conclusion of the rate proceeding for large general customers on Default Service is 0.1%.

OUTDOOR LIGHTING SERVICE CUSTOMERS (SCHEDULE OL)
Unitil's requested temporary rate increase would result in an average increase in monthly bills of approximately 1.4% this summer. The projected average change in monthly bills at the conclusion of the rate proceeding for outdoor lighting customers on Default Service is a decrease of 0.6%.

NEW SERVICES

In its filing, Unitil included several new offerings related to time-based energy rates (TOU), electric vehicle (EV) charging, and light emitting diode (LED) Outdoor Lighting. These offerings include:

DOMESTIC "WHOLE-HOUSE" TOU (TOU-D)
The Domestic "Whole-House" TOU rate is offered to allow residential customers to benefit from time-based energy optimization and includes peak, mid-peak and off-peak rates without the costs of a separate service, and may also include EV charging.

DOMESTIC EV TOU (TOU-EV-D)
The Domestic EV TOU rate is offered to allow separately-metered EV charging at customers' homes, and includes peak, mid-peak and off-peak rates.

SMALL GENERAL SERVICE EV TOU (TOU-EV-G2)
The small general service EV TOU rate is offered to allow businesses, municipalities, and other small general service customers to support EVs by offering options such as charging fleet vehicles, offering EV charging to patrons and customers, and developing publicly available merchant EV charging.

LARGE GENERAL SERVICE EV TOU (TOU-EV-G1)
The "high demand draw" large general service EV TOU rate is offered to provide separately-metered EV charging for customers such as passenger car fleet customers, heavy duty vehicles, or large public charging sites, including clustered Level 2 or Direct Current Fast Chargers.

LED OUTDOOR LIGHTING
The Company is proposing to add LED fixtures to Schedule OL where the Company would purchase, install, and maintain the LED fixtures in the same manner as the legacy lighting fixture types. Customers wanting to purchase their own LED fixtures will still have that option under Schedule LED if they meet the requirements of Schedule LED.

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY

OF

ROBERT B. HEVERT, CFA

EXHIBIT RBH-1

New Hampshire Public Utilities Commission

Docket No. DE 21-030

TABLE OF CONTENTS

LIST OF EXHIBITS

I. INTRODUCTION

Q. Please state your name, position, and business address.

A. My name is Robert Hevert. I am Senior Vice President, Chief Financial Officer and Treasurer of Unitil Corporation. I also serve as a Senior Vice President for each of Unitil Corporation's operating utility subsidiaries, including Unitil Energy Systems, Inc. ("UES" or the "Company").

Q. Please describe your professional experience and educational background.

A. I have worked in regulated industries for over 30 years, having served as an executive and manager with consulting firms, a financial officer of a publicly traded utility (at the time, Bay State Gas Company), and an analyst at a telecommunications utility. As a consultant, I advised energy and utility clients throughout North America on a wide range of strategic, financial, regulatory, and economic issues, and provided testimony in more than 300 proceedings across numerous jurisdictions, including the Commission, the Federal Energy Regulatory Commission, the Province of Alberta, Canada, the American Arbitration Association, and U.S. District Courts. In July 2020, I accepted my current position with Unitil Corporation. My responsibilities include the management and oversight of Unitil Corporation's finance, accounting, regulatory, legal, and energy supply functions.

Regarding my educational background, I hold a Bachelor's degree in Business and Economics from the University of Delaware, and a Masters of Business Administration, with a concentration in Finance, from the University of Massachusetts, Amherst. I also hold the Chartered Financial Analysts designation. A summary of my professional and educational background is provided in Exhibit RBH-2.

Q. What is the purpose of your Direct Testimony?

A. The purpose of my testimony is to provide a brief summary of UES, including its operations and strategic priorities, explain the key factors underlying our rate application, summarize the key proposals contained in this filing, and introduce the witnesses supporting the Company's proposed multi-year rate plan.

Q. Were your Direct Testimony and Exhibits prepared by you or under your direction?

A. Yes, they were.

II. EXECUTIVE SUMMARY

Q. Please summarize the Company's proposals in this proceeding, and the factors motivating those proposals.

A. This is a pivotal time for the electric distribution industry in general, and for UES in particular. Energy technology is rapidly evolving, public policies addressing climate change are quickly advancing, customer requirements are becoming increasingly sophisticated, the need for enhanced physical and cyber security is growing, and system reliability and resilience remain paramount. Those factors have changed how the electric grid is used, and what will be demanded of it as customers more actively manage their energy use, and adopt distributed resources, electric vehicles, and other advanced technologies to reduce carbon emissions.

For over a decade, Unitil Corporation's objective has been to create the platform that will enable those changes while providing the reliable and affordable service our customers demand. Our day-to-day focus is on the strategic, operating, financial, and regulatory priorities critical to that outcome. This application is among those priorities. Beyond seeking needed rate relief, our application includes several initiatives to advance New Hampshire's energy, environmental, and regulatory policies: Investments in grid modernization and electric vehicle charging infrastructure; time of use rates to manage whole-house electricity costs, and to minimize electric vehicle charging costs; and Revenue Decoupling to mitigate the financial consequences of declining customer use due to active and passive energy conservation.

Although our strategic priorities are forward-looking, we also focus intensely on near-term cost control, operating excellence, and customer satisfaction. Those efforts are reflected in our competitive delivery rates, continually improving reliability metrics, widely recognized ability to provide mutual assistance in response to weather events, and record high levels of customer and employee satisfaction. We are pleased to have achieved those results despite the challenges created by the COVID-19 pandemic.

We also appreciate that the constructive regulatory environment in New Hampshire has supported our ability to undertake a series of long-term initiatives designed to provide exceptional service, and to advance our customers' ability to adopt new technology and better manage their energy consumption. The multi-year rate plans the Commission has approved in the past have been essential to our ability to commit capital and resources to those initiatives, to our customers' ability to realize the benefits those commitments bring, and to our collective ability to avoid the time and expense required by serial base rate proceedings.

As in prior rate requests, the Company's revenue deficiency in this case is driven principally by unrecovered costs associated with capital investments. Because the fundamental factors driving our application in this case are similar to those underlying our recent rate filings, we have proposed a comparable multi-year structure. Our application in this proceeding includes a permanent rate request of approximately $12.0 million, proposed temporary rates of about $5.8 million, and a series of three step adjustments to recover costs associated with non-growth related capital investments for the calendar years 2021, 2022, and 2023. Consistent with the Commission's direction, we propose a Revenue Decoupling Mechanism. And to support our customers' ability to adopt electric vehicles and better manage their energy costs, we recommend a suite of time varying rates, including rates applicable to electric vehicle charging.

Also consistent with prior multi-year rate plans, our application includes a suite of customer protection provisions. Among other recommendations, we propose a Rate Cap limiting the revenue increase in any given year to 2.50 percent of the prior year's total electric operating revenue;[1] a Stay Out provision under which the Company would not seek base rate adjustments, subject to certain exogenous events, through calendar year 2024; and an Earnings Sharing provision that would share earnings above 11.00 percent

[1] With revenue for externally supplied customers being adjusted by imputing the Company's default service charges for that period. Any amount of the revenue requirement above the 2.50 percent cap would be deferred at the overall rate of return determined in this docket.

(that is, 100 basis points above our proposed Return on Equity) equally between distribution customers and the Company.[2] We also propose to apply approximately $2.64 million of Excess Accumulated Deferred Income taxes to the uncollected Major Storm Cost Reserve balance (approximately $3.28 million), significantly reducing the uncollected balance without increasing customer rates.[3]

In addition to those measures, we deferred seeking rate relief beyond 2020, even though our earned return had fallen more than 300 basis points below our 9.50 percent authorized Return on Equity. Further, although our expert recommends a Return on Equity of 10.20 percent, we propose 10.00 percent, toward the lower end of the recommended range. Those decisions, together with the provisions summarized above and our commitment to operating and capital cost management, intend to mitigate the rate effect on customers.

As we discuss throughout this application, our objective has been to provide a series of integrated proposals that balance the interests of our many stakeholders. We take seriously our obligation to provide our customers with exemplary service, and our responsibility to meet their evolving needs in the increasingly complex energy environment. If approved, our multi-year rate plan will enable us to continue doing both.

[2] Under that structure, the Company would retain the risk of earnings below 10.00 percent unless the actual return fell below 7.00 percent, at which point the Company may seek base rate relief.

[3] *See*, Testimony of Christopher J. Goulding and Daniel T. Nawazelski, at 35-36.

III. OVERVIEW OF THE COMPANY'S OPERATIONS

Q. Please briefly summarize Unitil Corporation's structure, and UES's place within it.

A. Incorporated in 1984 under the laws of New Hampshire, Unitil Corporation is a public utility holding company whose principal business is the local distribution of electricity and natural gas to approximately 192,600 customers. Those operations are carried out by four wholly owned utility subsidiaries: Unitil Energy Systems, Inc., which provides electric distribution service to approximately 77,200 customers in the seacoast and state capital regions of New Hampshire; Fitchburg Gas and Electric Light Company ("FG&E"), which provides electric and natural gas service to about 46,000 customers in the greater Fitchburg area of north central Massachusetts; Northern Utilities, Inc. ("Northern"), which provides natural gas service to approximately 69,400 customers in southeastern New Hampshire, and portions of southern and central Maine; and Granite State Gas Transmission, Inc. ("Granite State"), an interstate natural gas transmission company serving Northern Utilities in New Hampshire and Maine.

Unitil Corporation also holds three non-utility subsidiaries: Unitil Service Corp. ("Unitil Service"), which provides administrative and professional services, at cost, to its corporate affiliates[4]; Unitil Realty Corp., which owns and manages Unitil Corporation's corporate headquarters in Hampton, New Hampshire; and Unitil Resources, Inc., which

[4] Including regulatory, financial, accounting, human resources, engineering, operations, technology, and energy supply services.

had been the parent of Usource, an energy brokerage and advisory service that Unitil Corporation divested in 2019.[5]

Q. Are Unitil's utility operations geographically contiguous?

A. Although UES and Northern serve common communities in the seacoast region, UES and FG&E serve distinct geographic areas in New Hampshire and Massachusetts, respectively.

Q. Given that geographic footprint, are Unitil Corporation's utility subsidiaries managed on a centralized basis?

A. Yes, we manage our utility operations in a centralized, integrated manner through Unitil Service. That organizational structure is designed to realize scale economies, eliminate duplicate functions, share services and systems, and adopt best practices across corporate affiliates.

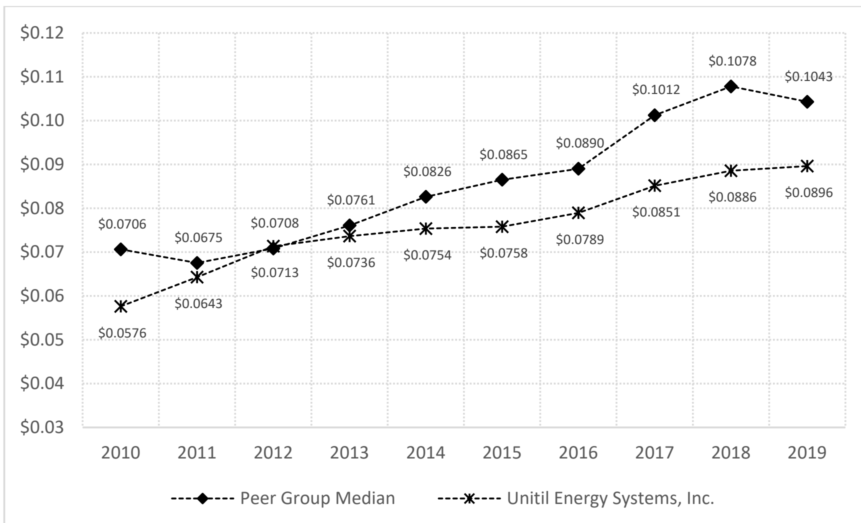
Q. Has the Company's focus on operating and capital cost control benefited its customers?

A. Yes, in the form of lower rates. From 2010 through 2019 (the most recent period for which comparative data is available), UES's average residential delivery rate ($/kilowatt-

[5] Unitil Corporation also holds Unitil Power Corp., which had functioned as the full requirements wholesale power supply provider for UES, but currently has limited business and operating activities. In connection with electric industry restructuring in New Hampshire, Unitil Power Corp. ceased being the wholesale supplier for UES in 2003, and divested substantially all of its long-term power supply contracts through the sale of the entitlements to the electricity associated with those contracts.

hour, or "kWh") consistently remained below the median rate for other electric distribution utilities operating in our region (see Chart 1, below).

Chart 1: Average Residential Delivery Rate ($/kWh)[6]



Even though we continuously manage our day-to-day operating costs and apply a rigorous capital budgeting process, the combination of increasing capital investments and decreasing customer use has put considerable pressure on UES's earned returns. As Messrs. Goulding and Nawazelski note, the Company currently is earning far below its authorized return.[7]

6 Source: S&P Global Market Insight. Peer Group includes Central Maine Power Company, Liberty Utilities (Granite State Electric) Corp., Massachusetts Electric Company, Nantucket Electric Company, NSTAR Electric Company, Public Service Company of New Hampshire, Versant Power, Western Massachusetts Electric Company. Please note, Unitil Electric Service's 2019 reported delivery rate ($.0896) is consistent with the rate reported in the Company's 2019 Form EIA 816, at 10.

7 Testimony of Christopher J. Goulding and Daniel T. Nawazelski, Filing Requirement Schedules, Page 12.

Q. Has UES also continued to focus on operations and system reliability?

A. Yes, it has. Mr. Sprague describes the Company's disciplined approach to reliability planning, including the daily, weekly, monthly, and annual analyses we apply to understand and address overall reliability performance. That approach has been effective; the Company's SAIDI and SAIFI indices generally have declined over the past ten years.[8] Moreover, in 2020 Unitil Corporation (through its utility subsidiaries) provided restoration aid to other local utilities after weather events eight times (a record number for Unitil Corporation), most notably after Tropical Storm Isaias.[9] That commitment to assisting other utilities has been consistent over time - we have received the EEI Mutual Assistance Award in three of the past four years.

Q. Has the Company's Vegetation Management Program also supported its reliability efforts and results?

A. Yes, it has. Ms. Sankowich explains that our Vegetation Management Program focuses on continuously improving reliability, customer satisfaction, safety, and maintenance efficiency. It does so through four components, each of which is designed to minimize the potential for contact between vegetation and utility lines. The Company's Storm Resiliency Program, which complements our Vegetation Management Program, is intended to reduce tree exposure along targeted circuits to improve system resilience during major storm events. As Ms. Sankowich notes, by improving system reliability the

[8] System Average Interruption Duration Index, System Average Interruption Frequency Index. See, Testimony of Kevin E. Sprague, at 3 – 5.

[9] Following Tropical Storm Isaias, Unitil restored service to all customers within 24 hours.

Storm Resiliency Program intends to increase customer satisfaction, reduce safety risks, and avoid costs during major storm events.[10] Because its many benefits more than offset its cost, we propose continuing the Storm Resiliency Program.[11]

Q. Is the Company's commitment to cost control and system reliability reflected in its customer satisfaction rates?

A. Yes, Unitil Corporation believes customer satisfaction is integrally related to cost, system reliability, and service restoration. In 2020, our customer satisfaction rate reached an all-time high of 93.00 percent, the highest among eight ranked utilities in the Northeastern United States, and tenth of 114 utilities nationally.[12] Although we take a measure of pride in our customer satisfaction and industry recognition, we take neither for granted. Rather, we continuously focus on the operational excellence our customers expect. Many of the initiatives we propose in this filing therefore intend to further enhance system reliability and resilience.

Q. Has Unitil Corporation's employee satisfaction also remained strong?

A. Yes, it has. Despite the challenges presented by the COVID-19 pandemic, in 2020 we achieved our highest-ever levels of employee pride and engagement:

[10] Testimony of Sara M. Sankowich, at 21-22.
[11] Testimony of Sara M. Sankowich, at 23-24.
[12] 2020 Escalent CSAT Survey

- Approximately 90.00 percent of employees say they are proud to work at Unitil Corporation;
- 91.00 percent of employees would recommend Unitil Corporation as a place to work; and
- 93.00 percent of employees feel Unitil Corporation is a good corporate citizen that cares about the community.[13]

We believe our strong employee satisfaction and pride also reflects Unitil Corporation's response to the COVID-19 pandemic. Early in 2020, Unitil Corporation formed a task force to track the virus and plan for its potential spread. By February, that team had engaged all levels of Unitil Corporation's management and by early March, implemented its plan and Incident Command Structure to respond to the emergency. By the time stay-at-home orders were issued in our service territories, Unitil Corporation had established and implemented extensive remote work capabilities. Our dispatch teams worked from secure, distanced spaces in separate locations, we established an enhanced cleaning protocol and staggered shift times to minimize the exposure of field personnel, and acquired additional vehicles to limit employee capacity. Despite those challenges, we continued to improve system reliability, maintained our focus on operating and capital cost management, advanced our Grid Modernization strategy, and achieved record high levels of customer and employee satisfaction.

[13] Based on survey results among non-collective bargaining employees.

Q. Lastly, was the COVID-19 pandemic a factor considered in determining when UES would file its rate application?

A. Yes, it was. Any decision to seek rate relief must consider the sometimes-competing interests of multiple stakeholder groups, and how those interests are best served over the long run. Although complicated under the best of circumstances, the economic stress and prevailing uncertainty during 2020 weighed heavily in the Company's decision. There was no question the COVID-19 pandemic had strained our customers and the communities we serve. From that perspective, the decision to defer our rate filing was straightforward. At the same time, all stakeholders have an interest in a financially healthy utility, and further deferring rate relief would put greater pressure on the Company's credit profile. We also appreciate that public policy-related objectives, for example encouraging electric vehicle adoption through time of use rates, are best supported by timely rate proposals.

On balance, we determined it was in our stakeholders' overall best interests to defer our rate application beyond 2020, even though UES had earned far below its authorized return. Given the extent of that earnings attrition and the importance of our planned capital investments, however, we could not defer the filing date beyond early 2021. Still, we are conscious of this filing's rate effects for our customers and as such, our proposal contains specific rate mitigation and ratepayer protection measures. We believe those measures, along with our continuing commitment to cost control and operating performance, will ensure our rates remain reasonable as we invest the capital needed to maintain a safe, reliable, resilient, and advanced electric grid.

IV. FACTORS UNDERLYING THE COMPANY'S RATE APPLICATION

A. The Company's 2016 Rate Application

Q. Are the factors underlying the Company's application in this case similar to those in DE 16-384?

A. Yes, our request in this case is driven in large part by factors that likewise motivated our 2016 application: (1) significant earnings attrition associated with unrecovered capital investments during and since the Company's last multi-year rate plan; (2) timely recovery of future capital investments in the plant and equipment needed to modernize the distribution system and ensure its continued reliability; (3) rate design enhancements needed to support our customers' changing preferences, and to provide the revenue required to support our operations and investments; and (4) ratepayer protection provisions intended to temper the rate effect on our customers.

Q. Please summarize UES's last multi-year rate application.

A. The Company's most recent application, docketed as DE 16-384, was filed on April 29, 2016. In that case, UES requested a base rate increase of approximately $6.3 million, with a temporary rate increase of about $3.0 million (subject to refund or recoupment). Similar to the multi-year structure included in its 2010 filing (DE 10-055), in its 2016 case the Company proposed a series of five step adjustments that would become effective on May 1st of each year from 2017 through 2021, reflecting capital additions made during the calendar years 2016 through 2020. The revenue requirement associated with those step adjustments included only the pre-tax rate of return, depreciation and amortization, and property taxes on the incremental non-revenue producing capital invested each rate year. As measures of customer benefits and protection, the multi-year plan included a 2.00 percent limit on rate increases in any year during the plan, an Earnings Sharing Mechanism, and a Stay Out provision prohibiting the Company from filing a general rate case before 2021.[14]

On June 28, 2016, the Commission approved a stipulation and settlement agreement among the Company, Commission Staff ("Staff"), and the Office of Consumer Advocate ("OCA") setting temporary revenue at about $2.4 million, effective July 1, 2016.[15] In February 2017, Staff filed a comprehensive settlement agreement among the Company, the OCA, and Staff resolving all contested issues in the case (the "Settlement").[16] Among other things, the Settlement provided a permanent distribution rate increase of approximately $4.1 million, and three step adjustments reflecting: (1) additions to net plant through calendar year 2016, with rates effective May 1, 2017; (2) 80.00 percent of changes in net plant during calendar year 2017 with rates effective May 1, 2018; and (3) 80.00 percent of changes in net plant during calendar year 2018, with rates effective May 1, 2019.[17] The sum of rate increases under the three step adjustments would not exceed $4.5 million.

14 Docket No. 16-384, Collin Testimony at 22.
15 Docket No. 16-384, Order No. 25,915 at 4, 8.
16 Docket No. 16-384, Exhibit 12.
17 The first step adjustment includes approximately $1.7 million of revenue to recoup the difference between temporary rates ($2.4 million) and permanent rates ($4.1 million). See, State Of New Hampshire Public Utilities Commission DE 16-384, Unitil Energy Systems, Inc., Petition for Distribution Rate Increase Order Approving Settlement Agreement Order No. 26,007, April 20, 2017, at 8.

The Settlement also included a Stay Out provision prohibiting the Company from filing a general rate case before December 31, 2019 unless its reported earned Return on Common Equity fell below 7.00 percent, and an Earnings Sharing Mechanism under which 50.00 percent of earnings in excess of a 10.50 percent Return on Equity ("ROE") would be returned to customers.[18] Lastly, the Settlement included a provision for Exogenous Events, which would adjust rates upward or downward in response to "actions of state or federal government agencies, regulatory cost reassignments, or changes in accounting rules" of at least $200,000.[19] In Order No. 25,007 the Commission approved the Settlement, noting its continuing preference for disputed issues to be resolved through negotiation and compromise.

Q. Did the Company's filing in Docket 16-384 explain the factors underlying its need to seek rate relief?

A. Yes, UES explained that although the step adjustments approved in DE 10-055 helped moderate earnings attrition, it continued to invest capital beyond 2014, the rate year for the final step adjustment in that docket. The Company further explained that since 2010, kilowatt-hour unit sales essentially had remained flat, and customers grew at an annual rate of 0.50 percent. The combination of low customer growth and flat use per customer limited the Company's revenue growth. At the same time, continuing investments in

[18] State Of New Hampshire Public Utilities Commission DE 16-384, Unitil Energy Systems, Inc., Petition for Distribution Rate Increase Order Approving Settlement Agreement Order No. 26,007, April 20, 2017, at 9 - 10.

[19] State Of New Hampshire Public Utilities Commission DE 16-384, Unitil Energy Systems, Inc., Petition for Distribution Rate Increase Order Approving Settlement Agreement Order No. 26,007, April 20, 2017, at 12 – 13.

non-revenue producing assets caused its fixed costs - principally deprecation, property taxes, and required returns - to increase. The increasing fixed costs, together with ongoing inflationary pressures on operating expenses, forced the Company's costs to increase faster than its revenues. The resulting earnings attrition continued despite the Company's focus on cost controls.[20]

B. <u>Continuing Earnings Attrition</u>

Q. Please explain the term "earnings attrition", and how it applies to utilities such as UES.

A. In general, earnings attrition is the decline in returns that occurs when revenues do not keep pace with costs. Like all utilities, UES is a capital-intensive enterprise, requiring ongoing investments in long-lived physical assets and incurring the fixed costs associated with them. Companies operating in capital-intensive sectors tend to share two traits: they have relatively high proportions of fixed to variable costs (that is, they have relatively high degrees of "operating leverage"), and they produce fewer dollars of revenue for each dollar of invested assets than firms operating in other sectors.[21]

As with financial leverage, operating leverage tends to magnify the effect of changes in revenue on operating income. Intuitively, if revenues fall, the larger portion of a utility's cost structure, its fixed costs, will remain and its earnings will fall at a faster rate. That is a particular concern when utility rates are substantially volumetric and use per customer

[20] *See*, Docket DE 16-384, Testimony of Mark H. Collin, at 9 – 13.
[21] *See, e.g.,* J. Fred Weston, Eugene F. Brigham, <u>Essentials of Managerial Finance</u>, 9th Ed., The Dryden Press, 1990, at 371 – 373. *See*, also, Testimony of Ronald J. Amen, at 13 – 14.

declines. In that case, even if the customer count increases and operating costs are well-managed, revenue may not increase keep pace with costs, leading to earnings attrition.

The second characteristic of capital intensity, the tendency to produce relatively little revenue for each dollar of assets, speaks to the need for timely recovery of invested capital. Here too, the reasoning is intuitive: Absent timely recovery, revenue will not be sufficient to cover incremental costs, leading to earnings attrition.

Q. Has the Company's ongoing capital investments led to continued earnings attrition?

A. Yes, it has. The Company's calculated revenue deficiency is driven largely by unrecovered costs associated with capital investments not included in the step adjustments provided in the Company's last multi-year rate filing[22], and investments made since 2018, the last rate year reflected in those adjustments. Since the Company's filing in DE 16-384, which included a pro forma 2015 test year, UES has invested approximately $124.79 million in its distribution system. Although the multi-year rate filing approved in that case provided a measure of cost recovery, about $88.08 million of those investments (approximately 71.00 percent) have not been recovered under any rate mechanism.

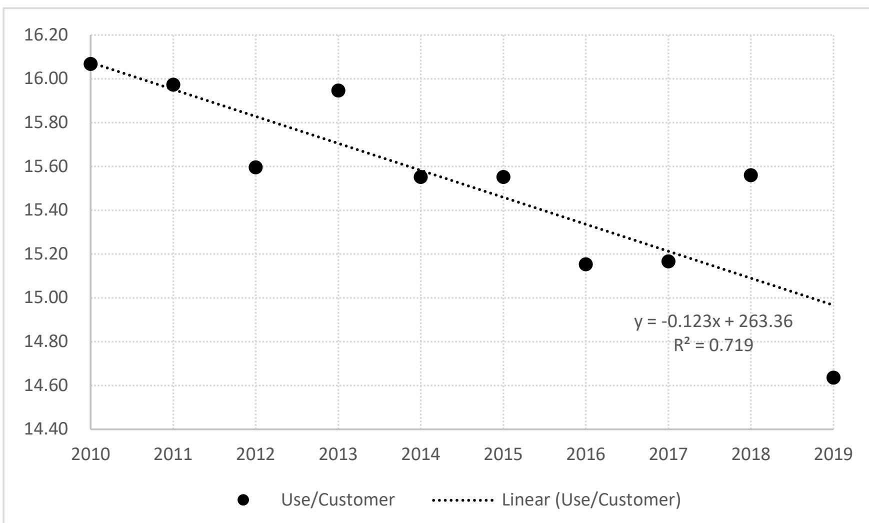
Q. Have the Company's customers and sales volumes increased over time?

A. Although UES has been able to steadily increase its number of customers, sales volumes have fallen. From 2010 through 2019, customers grew at an average annual rate of about

[22] The Settlement Agreement limited the second step adjustment to the revenue requirement associated with 80.00 percent of changes in Net Plant in Service over the prior year, and the third adjustment to no more than 80.00 percent. The sum of the three step adjustments (including 2017, 2018, 2019) would not exceed $4.5 million. *See*, DE 16-384, Order No. 26,007, at 8.

0.43 percent, whereas volumes declined at an annual rate of negative 0.58 percent. More recently (2016 through 2019) customers increased at average annual rate of 0.40 percent and volumes declined by negative 1.07 percent. The combination of increasing customers and lower total volumes has led to consistently declining use per customer (see Chart 2, below).

Chart 2: Use per Customer (MWh)[23]



Nonetheless, we have continued to invest in the assets and systems needed to provide our customers the information they require to manage their energy use.[24] Because our Grid Modernization investments will support a growing number of customers able to consume

[23] Source: S&P Global Market Insights

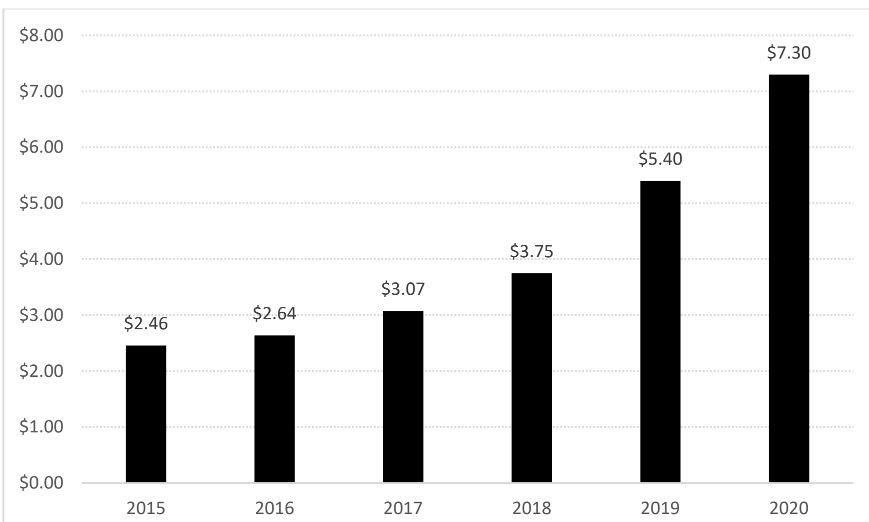
[24] The correlation between the number of customers and the Company's net plant has been positive 96.00 percent, whereas the correlation between the sales volumes and net plant has been negative 34.00 percent. Source: S&P Global Market Insights

less electricity, absent the timely recovery of those costs our future earnings and cash flows will be further diluted.[25]

Q. Beyond its Grid Modernization initiatives, has the Company continued to support end-use energy efficiency programs?

A. Yes, it has. Since 2016, UES has committed over $22 million to end-use energy efficiency programs. That commitment has accelerated considerably over the past five years, increasing from about $2.6 million in 2016 to nearly $7.3 million in 2020 (see Chart 3, below).

Chart 3: Annual Energy Efficiency Spending ($millions)[26]



Although we certainly support public policy objectives relating to energy conservation, our existing rate design, including the Lost Revenue Adjustment Mechanism, may leave

[25] Mr. Diggins addresses in more detail the effect of cash flow erosion on the Company's credit metrics, and its ability to efficiently access capital markets.

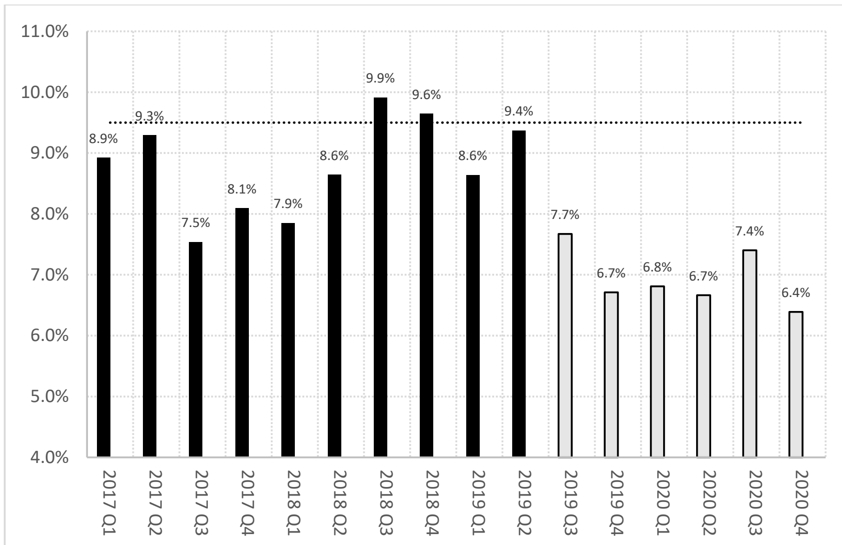
[26] FERC Account 908, Customer Assistance Expenses. Program costs and performance incentives are recovered though the System Benefits Charge.

the customers and the Company susceptible to variations in volumes. As Mr. Lyons explains, that variation, together with the misalignment between volumetric-based utility rates and the fixed nature of utility cost structures, motivates our proposed Revenue Decoupling Mechanism.

Q. Has the combination of declining use and increasing investments eroded the Company's earnings?

A. Yes, it has. Since the third calendar quarter of 2019 (when the last step adjustment approved under DE 16-384 became effective), the Company's earned Return on Equity has fallen considerably, and remains well below the 9.50 percent return authorized in that case (see Chart 4, below). In fact, over the six calendar quarters following the last step adjustment, the Company's average earned ROE was 7.46 percent, 204 basis points below the authorized level. During the most recent quarter (the fourth quarter of 2020) the Company under-earned its authorized return by more than 300 basis points.

Chart 4: UES Earned ROE (2017 – 2020)[27]



Q. What steps has the Company taken to mitigate earnings attrition?

A. UES has focused on cost management and supporting customer growth. As discussed earlier, Unitil Corporation manages its utility operations in a centralized manner, realizing efficiencies from scale economies, avoiding duplicate activities, and adopting best practices. Those efforts are reflected in Operating and Maintenance ("O&M") cost levels that, since 2015, increased at an annual average rate of only 1.60 percent.[28] As a point of reference, over the same period the average annual (regional) inflation rate was about 2.20 percent.[29]

27 Provided in Company FERC Form 1 or FERC Form 3Q per PUC 308.11 F-1 Supplemental Quarterly Financial and Sales Information.

28 Refers to Unitil Energy Systems O&M expense. Excludes Total Power Supply Expense, Total Transmission Expense, Total Regional Transmission and Market Operations Expense, Customer Assistance Expenses.

29 Source: Federal Reserve Bank of St. Louis Economic Research, data series CUURA103SA0. Annual inflation measured as year-over-year increase as of January 1.

Although the Company has successfully managed its operating expenses, fixed costs arise from capital investments. It is for that reason our capital investment plan undergoes a rigorous budgeting and approval process. Ours is a "bottom-up", multi-step, iterative approach structured to evaluate and prioritize projects offering the most cost-effective means of providing safe and reliable electric distribution service. The process requires multiple rounds and levels of evaluation on a project-by-project basis, culminating in review and approval by Unitil Corporation's senior management, and Board of Directors. Even after the overall capital budget is approved, each project must be authorized before budgeted funds may be invested.[30]

Q. Are those factors (*i.e.*, declining use per customer, increasing capital investments, and operating cost control) reflected in the Company's proposed rate structures?

A. Yes, they are. As explained above, our proposed base rate increase and annual step adjustments are driven by past capital investments not yet included in rates, and future capital investments required to maintain and modernize the electric distribution system. They are not principally driven by operating cost increases. And as discussed below, our proposed rate structures, including the proposed Revenue Decoupling, and Time of Use rate structures, address declining customer use and evolving customer preferences.

[30] Exceptions may occur during an unforeseen emergency that requires capital spending to ensure public safety, or to restore service. *See*, also, Testimony of Kevin E. Sprague, at 8 – 13.

C. <u>Investments in the Advanced Energy Grid</u>

Q. Before discussing the Company's Grid Modernization investments, please briefly summarize how the operating environment for electric distribution utilities has evolved.

A. Like other electric distribution utilities, UES operates in an environment in which energy-related technology and stakeholder interests are evolving at an accelerating rate. Advancements in technology, evolving public policy regarding climate change, and increasingly sophisticated customer preferences have changed how the electric grid will be used, and what will be asked of it. Those factors, together with the attendant need for enhanced physical and cyber security, and the continuing need to ensure system reliability, are rapidly transforming the longstanding model of energy delivery. In short, customers now expect a more reliable and resilient electric grid as protection from the increasing frequency and severity of climate change-induced weather events, a broader array of information made available by the transition to digital technology, and the ability to adopt distributed energy resources, electric vehicles, and other technology to manage end use and reduce carbon emissions.

Q. What are the implications of those changes for the Company's operations?

A. Rather than operating under the traditional model in which utilities provide the one-way distribution of energy, electric distribution companies now must manage a grid that provides safe and reliable service to customers that both consume and produce power, accommodates a growing range of distributed energy resources, accommodates evolving end-use technology, and transmits information allowing customers and producers to optimize their energy-related decisions.

The electric grid must become the platform enabling the efficient and reliable two-way flow of electricity and information; it must provide customers greater control over energy use, enable distributed renewable energy resources, enhance system reliability and resilience, and advance system security.[31] As Mr. Sprague explains, "foundational" investments in Information Technology and Operational Technology are required to establish and maintain that platform. Those investments, together with specific ratemaking and customer-facing initiatives, form the basis of the Company's Grid Modernization plan.

Q. Please provide an overview of the Company's Grid Modernization plan, and how it addresses the interests of the Company's stakeholders.

A. Let me begin by noting that our stakeholders represent varied groups, including our customers, employees, investors, the communities we serve, state and federal policy makers, environmental and consumer advocacy organizations, and others. Though diverse, our stakeholders have a common interest in an electric distribution system that provides safe, reliable, and affordable electric service in a manner that supports public policy, encourages technological innovation, enables energy use optimization, and enhances customer experience.

[31] See, also, *Unitil's 2020 Sustainability R*eport, https://unitil.com/2020-Sustainability-Report/11/

That common interest, which complements our vision of the advanced electric grid, is supported by a series of eight foundational objectives Unitil Corporation has developed with guidance from the Commission, the Massachusetts Department of Public Utilities, and the United States Department of Energy.[32] Unitil Corporation, and UES, have looked to those objectives in developing the Company's Grid Modernization plan, which includes six fundamental initiatives:

1. *Grid Intelligence*: With the continuing integration of distributed, variable, and renewable resources on the distribution system, and increased focus on electric vehicles, increased visibility into and control of the distribution system is essential. System optimization and the efficient use of grid resources is an increasingly critical element of providing a safe, reliable, sustainable, and cost-effective electric distribution system. The Company's vision of Grid Intelligence includes centralized information systems and field devices supporting Advanced Distribution Management Systems, Distributed Energy Resources Management Systems, Outage Management Systems, the Supervisory Control and Data Acquisition ("SCADA") system, Volt/Var Optimization, and the further integration of Advanced Metering Infrastructure.

2. *Advanced Metering Functionality ("AMF"):* AMF provides the platform to measure and provide detailed, granular interval metering data for individual

[32] *See*, Testimony of Kevin E. Sprague, at 38-39 (the eight objectives are: Environmentally Friendly; Safety and Reliability; Customer Service; Security; Flexibility; Affordability; Demand and Asset Optimization; and Technology Innovation).

customers. That platform is enabled by investments in Advanced Metering Infrastructure, which automatically measures and reports electric usage; Interval Metering, a more granular record of energy consumption during regular intervals; and Metering Data Management Systems, which processes and manages meter operations data, and facilitates the integration of that data with other systems including Customer Information, and Outage Management Systems.

3. *Distributed Energy Resources ("DER")*[33]*:* The Company's vision of an advanced energy grid enables the interconnection of large numbers of renewable and other distributed energy resources. Integrating large and growing, numbers of renewable and intermittent resources requires investments in advanced monitoring and control technology to evaluate and optimize distribution system use in real time.

4. *Advanced System Planning and Forecasting:* Advanced system planning and forecasting methods enable system optimization by taking into account intermittent generation and controllable load resources. Forecasting distributed energy resources and electrification technologies (for example, electric vehicles) is critical to their adoption. The Company has implemented several systems to enable accurate, real-time forecasting, including: Advanced Geographic Information Systems ("GIS"), which provide spatial

[33] Generally speaking, Distributed Energy Resources are electricity producing resources connected to the distribution system.

representations of the distribution system, and the resources connected to it; Real-Time System Planning processes that depend on the Advanced Distribution Management, Distributed Energy Resource Management, SCADA, and Volt/Var Optimization Systems; DER Forecasting methods, which rely on spatial GIS systems to ensure the system is prepared to interconnect DERs; Electrification Forecasting methods; Hosting Capacity Analysis to more efficiently evaluate the capacity of a given substation or feeder line to "host" a given amount of distributed resources; and Locational Value Analysis, which assesses the value a distributed resource creates for the overall system.

5. *Enhanced Customer Services:* To ensure customers are able to derive the greatest possible value from the modernized energy grid, Unitil Service will continue to enhance our customer web portal, adding self-service options that enable customers to better manage their energy usage and accounts. Looking forward, our portal will extend customer value by providing more personalized options to address their individual needs.

6. *Innovative Rate Design*: The overarching objective of rate design is to develop pricing that adheres to the basic principles of fairness, transparency, and economic efficiency. Such structures will encourage behavior consistent with

policy objectives, establish equity among customers, and provide revenue sufficient to support the investments needed to modernize the electric grid.[34]

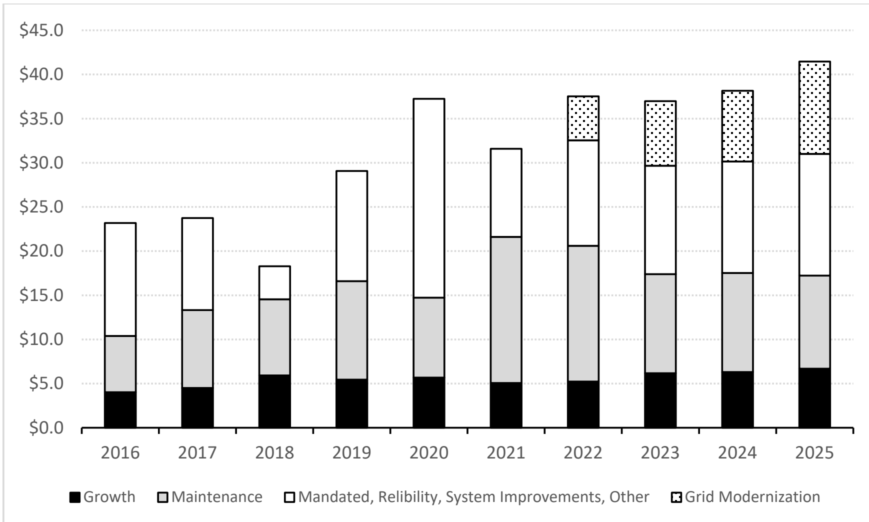
To be clear, we recognize that no single, definitive construct of the future electric grid has emerged. Our approach therefore considers the range of capabilities that will be required to develop and support the modernized electric grid. That is what we have done, and will continue to do. Taken together, the six categories of initiatives summarized above provide the capabilities and support the platform required to meet our stakeholders' growing expectations: Integrating advanced energy solutions, including distributed resources; reducing service interruptions; realizing shorter restoration times, in particular following major weather events; reducing greenhouse gas emissions; maintaining service affordability; and providing compensatory returns to our investors.

Q. With those objectives in mind, are investments in Grid Modernization likely to increase over the coming three to five years?

A. Yes, they are. As Chart 5, below, indicates, beginning in 2022, Grid Modernization investments become an increasingly large portion of the Company's overall capital investment plan.

[34] *See*, Testimony of Kevin E. Sprague, at 39 – 44.

Chart 5: Components of Capital Investments ($millions)[35]



D. Rate Design Enhancements

Q. Please summarize the rate design enhancements included in the Company's application.

A. Our application includes a proposed Revenue Decoupling Mechanism, and a suite of Time of Use rate offerings. In each case, the proposed rate structure supports policy objectives or directives established by the Commission, is consistent with the Company's goal of designing and implementing fair, transparent, and economically efficient rates, and provides a foundation for realizing the benefits enabled by an advanced electric grid.

Q. Why is the Company proposing a Revenue Decoupling Structure in this proceeding?

A. In Order No. 25,932 (Docket DE 15-137) the Commission required utilities to seek approval of a decoupling or other "lost revenue recovery mechanism" as an alternative to

[35] Source: Exhibit KES-2.

the existing Lost Revenue Adjustment Mechanisms ("LRAMs"). That requirement, which was recommended by the Settling Parties in Docket DE 15-137, applied to any distribution rate case "after the first EERS triennium, if not before."[36] Because the Company filed its application in DE 16-384 before that Order was issued, this case is our first opportunity to seek approval of a decoupling mechanism.

Beyond complying with that procedural directive, the Company agrees with the Commission's observations regarding decoupling structures, and the benefits they provide. As the Commission noted, LRAMs were meant to recover the portion of utility revenue requirements lost to energy efficiency activities. That is (as the Joint Utilities observed), an LRAM would set the utility in the position contemplated by the approved revenue requirement, but for efficiency activities; it was intended to isolate the revenue effect of efficiency.[37] At the same time, because a large portion of utility rates are consumption-based, if sales were to increase it is possible that under an LRAM, revenues could exceed the revenue requirement.[38]

Whereas consumption-based pricing structures may create a "throughput incentive" to recover fixed and variable costs through increased sales volumes, revenue decoupling structures do not. Rather, revenue decoupling removes the financial disincentive to pursue initiatives intended to reduce consumption.[39] That distinction is significant, given the Company's objective to enhance our customers' ability to manage their energy use.

[36] Docket DE 15-137, Order No. 25,932, at 60. *See, also*, Testimony of Timothy S. Lyons, at 4 – 5.
[37] *See*, Docket DE 15-137, Order No. 25,932, at 26-27.
[38] Docket DE 15-137, Order No. 25,932, at 59. *See, also*, Direct Testimony of Timothy S. Lyons, at 8.
[39] *See*, Direct Testimony of Timothy S. Lyons, at 11.

Our proposed Revenue Decoupling Mechanism therefore supports public policy objectives surrounding energy conservation, and is integral to our Grid Modernization plan.

Q. Lastly, please explain the strategic importance of the Company's proposed Time of Use rate structures.

A. As discussed above, the Company's Grid Modernization plan has several objectives, among them addressing climate change through the adoption of end-use technologies such as electric vehicles and distributed energy resources, and encouraging time-based energy consumption. In that respect, we encourage customers to actively manage their energy use, and to actively participate in the energy markets. Rate design is important to both. Our proposal therefore provides a suite of time-varying rates, including a residential "whole house" time of use rate, and separately metered electric vehicle time of use rates for residential and small and large general service customers.

The proposed residential whole-house time of use rate enables customers to optimize their energy consumption. It also provides a time-varying rate structure for electric vehicle customers with their own charging equipment, and enables a transition to separately metered rates, if desired. As Ms. Carroll, Mr. Simpson, and Ms. Valianti explain, such rate options may be important to residential customers who wish to manage their costs by reducing consumption during peak periods.

Ms. Carroll, Mr. Simpson, and Ms. Valianti also explain that broad electric vehicle adoption will depend on rate design, and the availability of charging infrastructure. Their testimony therefore presents three separately metered time of use rates for electric vehicle customers, a residential behind-the-meter Electric Vehicle Supply Equipment installation and incentive program, a "make-ready" electric vehicle infrastructure installation program to expand public charging stations, and a Marketing, Communications, and Education program to increase customer awareness of electric vehicle charging infrastructure and time of use rates.

V. THE COMPANY'S PROPOSED MULTI-YEAR RATE PLAN

A. Components of the Proposed Multi-Year Rate Plan

Q. Please briefly describe the principal elements of the Company's proposed rate relief.

A. As summarized below (and as explained more fully in the testimony of Messrs. Goulding and Nawazelski), our proposed multi-year structure includes the basic components contained in the settlement agreement approved by the Commission in our last rate proceeding: (1) a base rate increase of approximately $12.0 million based on the calendar year 2020 test year; (2) a temporary rate increase of $5.8 million, effective June 1, 2021; and (3) a series of three annual step adjustments reflecting the fixed costs associated with non-growth related capital investments over the calendar years ended 2021, 2022, and 2023. If approved without modification, a typical residential customer using 600 kWh per month would see an 8.20 percent increase in their total bill after accounting for changes to other reconciling mechanisms.[40]

Our calculated revenue deficiency is based on a test year ended December 31, 2020, adjusted for known and measurable changes for ratemaking purposes.[41] The revenue requirement reflects a rate base of $226.03 million, and an overall Rate of Return of 7.88 percent, including a Return on Equity of 10.00 percent. Of note, the total rate base includes approximately $67.1 million of gross plant additions since December 2018, the rate year for the last step adjustment provided in DE 16-384.[42]

Q. Please now summarize the Company's proposed temporary rate increase.

A. In keeping with RSA 378:27, our temporary rate request intends to provide a reasonable return on our existing utility investments.[43] To that end, our proposed temporary rates are based on the Company's year-end rate base, excluding (for the sake of conservatism) the known and measurable changes included in our permanent rate request, combined with an overall Rate of Return of 7.61 percent adjusted for the effective tax rate of 27.08 percent. Because our proposed overall Rate of Return in this case is less than the 8.34 percent return approved in DE 16-384,[44] our temporary rate request is not based on our

[40] Vegetation Management costs of $1.4 million, Lost Base Revenue recovery of $1.1 million and regulatory assessment costs of $0.2 as reflected in Messrs. Goulding and Nawazelski Testimony, Table 1 have been reclassified from reconciling mechanisms to base rates. Also refer Schedule JDT-3, Page 1.

[41] Please note that, net of tariff reclassifications, the increase in proposed base rates is approximately $9.4 million. *See*, Direct Testimony of Christopher Goulding and Daniel Nawazelski, Table 1.

[42] Compares Pro Forma December 31, 2020 Utility Plant in Service of $407,914,123 as shown on Schedule RevReq-4, Column 4, Line 1 to Gross Utility Plant of $340,808,318 as shown on the Company's 2018 FERC Form 1, Page 110, Column C, Line 2.

[43] For example, as of January 2021 the unemployment rate in New Hampshire was 3.50 percent relative to the national unemployment rate of 6.50 percent. Source: https://www.bls.gov/news.release/laus.nr0.htm#.

[44] Docket DE 16-384, Order No. 26,007 at 9.

currently authorized overall return. Rather, the proposed 7.61 percent Rate of Return reflects our currently proposed capital structure and cost of debt, together with the 9.50 percent Cost of Equity approved in DE 16-384 (rather than the 10.00 percent Cost of Equity proposed in this case).

The Company also proposes to continue recovering Lost Base Revenue through the System Benefits Charge until permanent rates become effective, reducing our proposed temporary rates by approximately $1.08 million. Based on those factors and considerations, the Company proposes temporary rates of $5.81 million.[45]

Q. Please also summarize the proposed annual step adjustments.

A. Similar to the structure approved in DE 16-384, our proposal in this proceeding includes a series of three step adjustments to reflect the fixed costs (return, depreciation, and property taxes) associated with eligible capital investments during calendar years 2021, 2022, and 2023. Eligible investments will include only non-growth related plant additions, which represent approximately 83.00 percent to 86.00 percent of all forecasted investments during the three calendar years ended 2023.[46]

Each January 31st (beginning 2022), the Company will make a compliance filing with the Commission to recover the revenue requirement associated with eligible plant additions made during the prior calendar year. The approved revenue requirement then would be recovered over rate years beginning April 1st and ending March 31st of the following

[45] *See*, Direct Testimony of Christopher Goulding and Daniel Nawazelski; *see*, also, Schedule CGDN-3, Page 1.

[46] Source: Exhibit KES-2.

year. Under that structure, the Company would make its first compliance filing on or before January 31, 2022 identifying the revenue requirement associated with eligible investments made during calendar year 2021, to be recovered over the rate year April 1, 2022 through March 31, 2023.[47]

Q. Lastly, please briefly summarize the Company's proposal relating to Vegetation Management and Reliability Enhancement expenses.

A. In each annual compliance filing, the Company would reconcile its actual Vegetation Management and Reliability Enhancement expenses with the $6.27 million included in rates pursuant to Docket No. DE 21-030. For the period January 1, 2021 through May 31, 2021, the reconciliation will reflect the Vegetation Management and Reliability Enhancement expenses included in rates in Docket No. 16-384; beginning June 1, 2021 the reconciliation will reflect expenses included under Docket No. DE 21-030; any over- or under-collections would be included in the Company's External Delivery Charge mechanism. With the Commission's approval the Company may credit unspent amounts to future vegetation management expenses.[48]

[47] Messrs. Goulding and Nawazelski present the proposed step adjustments in their direct testimony. See, also, Exhibit CGDN-1.

[48] *See*, Exhibit CGDN-1.

B. <u>Rate Effect Mitigation and Customer Protection Measures</u>

Q. Please summarize how UES has mitigated the rate increases reflected in this application.

A. First, as discussed earlier, UES remains committed to both operating and capital cost control. Second, and as also explained above, the Company chose to defer its filing beyond 2020, even though we had significantly under-earned our authorized return. Third, although we see circumstances in 2021 as improving and understand that by some measures New Hampshire has fared better than many other parts of the country,[49] we are mindful of the continuing unease in the region. We therefore reduced the requested Return on Equity from the 10.20 percent recommended by our expert[50] to 10.00 percent.

Q. Does the rate filing also include specific customer protection and rate mitigation mechanisms?

A. Yes, it does. The Company commits it will not seek base rate relief, subject to certain exogenous factors and other considerations, during the three-year term of its proposed step adjustments.[51] Beyond providing customers assurance they will not see further base rate increases during the stay out period, by not seeking base rate relief the Company forgoes the ability to adjust its authorized cost of capital during a period in which interest rates generally are expected to increase.[52]

49 For example, as of January 2021 the (seasonally adjusted) unemployment rate in New Hampshire was 3.60 percent relative to the national average of 6.30 percent. Source: U.S. Bureau of Labor Statistics, *State Employment and Unemployment Summary*, March 15, 20201.

50 *See*, Direct Testimony of Jennifer E. Nelson.

51 *See*, Direct Testimony of Christopher Goulding and Daniel Nawazelski, Schedule CGDN-1.

52 *See*, for example, Testimony of Jennifer E. Nelson at 29 - 31.

We also propose a Rate Cap, under which changes to distribution rates in any year of the multi-year rate plan would be limited to 2.50 percent of the prior year's total electric operating revenue.[53] Any amount of the revenue requirement above that cap would be deferred at the overall rate of return established in this docket.

We further propose a Return on Equity collar, which would share earnings above 11.00 percent (i.e., 100 basis points above the 10.00 percent proposed ROE) on an equal (i.e., 50/50) basis between customers and shareholders. The Company would retain the downside risk of earnings below 10.00 percent, except that if its earned Return on Equity falls below 7.00 percent during the Stay Out period, it may file a request for base rate relief.[54]

Beyond those mechanisms, we would apply approximately $2.64 million of Excess Accumulated Deferred Income taxes to the uncollected Major Storm Cost Reserve balance (approximately $3.28 million), significantly reducing the uncollected balance without increasing customer rates.[55]

[53] With revenue for externally supplied customers being adjusted by imputing the Company's default service charges for that period.
[54] *See*, Testimony of Christopher Goulding and Daniel Nawazelski, Schedule CGDN-1.
[55] Testimony of Christopher Goulding and Daniel Nawazelski, at 35 - 36.

C. <u>Proposed Rate Mechanisms</u>

1. Revenue Decoupling Mechanism

Q. Please briefly describe the Company's proposed Revenue Decoupling Mechanism.

A. As Mr. Lyons explains in more detail, the Company proposes a full revenue decoupling mechanism that would reconcile monthly variances between actual and authorized revenue per customer, by rate class (but for the Lighting and proposed Electric Vehicle rate classes). Under that proposal, the authorized revenue per customer would be adjusted to reflect the incremental revenue requirement associated with each of the three annual step adjustments. We also propose a deferral account that would carry, with interest, cumulative monthly variances (by rate class) over a twelve-month measurement period. A Revenue Decoupling Adjustment Factor then would refund customers any amount of revenues greater than authorized levels, or surcharge customers to the extent actual revenues fell below authorized levels. The proposed adjustments would be filed with the Commission each June 1st for its approval for effect August 1st.

2. Time of Use Rates

Q. Lastly, please briefly describe the Company's proposed Time of Use rates.

A. As noted earlier, our proposal includes a "whole-house" residential time of use rate and separately metered time-varying electric vehicle rates for residential, small general service, and "high demand draw" large general service customers. The separately metered rates will provide meaningful incentives to charge vehicles during off-peak hours, and the dedicated meter will ensure a separate rate class for electric vehicle charging that is manageable through demand response programs and is distinct from other electrical loads.[56]

VI. WITNESSES SUPPORTING THE COMPANY'S RATE FILING

Q. Please briefly introduce the witnesses supporting the Company's application in this proceeding.

A. The Company's comprehensive rate filing is supported by the information required under the Commission's rules, including the Standard Filing Requirements, together with testimony and exhibits demonstrating the need for permanent rate relief, and the reasonableness of our proposed multi-year plan. The Company's application is supported by the following witnesses:

- *Mr. Christopher Goulding*, *Director of Rates and Revenue Requirements*, *and Mr. Daniel Nawazelski, Lead Financial Analyst*, present the Company's Revenue Requirement, including test year revenues and expenses, including the effects of the COVID-19 pandemic on the test year; our proposed three-year step adjustments; our proposed Earnings Sharing Mechanism and the Company's proposed temporary rates. Messrs. Goulding and Nawazelski also introduce the proposed tariffs.
- *Mr. John Closson, Vice President of Shared Services and Organizational Effectiveness, and Mr. Joseph Conneely, Director of Human Resources,* address the Company's compensation and benefits programs. Mr. Closson

[56] *See*, Direct Testimony of Cindy L. Carroll, Carleton B. Simpson, and Carol Valianti.

also discusses the Company's recently completed Exeter, New Hampshire distribution operations center.

- *Mr. Kevin Sprague*, *Vice President of Engineering*, addresses the Company's annual planning and capital budget process, the effect capital investments have had on system reliability, and Unitil's Grid Modernization program.
- *Ms. Cindy Carroll, Vice President of Customer Energy Solutions, Mr. Carleton Simpson, Regulatory Counsel, and Ms. Carol Valianti, Vice President of Communications and Public Affairs* provide the Company's proposed suite of Time of Use rate structures, Electric Vehicle development program, and the Company's customer education program as it relates to its EV develop program and proposed Time of Use rate offerings.
- *Mr. Mark Lambert, Vice President of Customer Operations* explains the investment made by the Company to replace its legacy Customer Information System, which had been in service for more than twenty-two years.
- *Mr. Daniel Hurstak, Chief Accounting Officer and Controlle*r, provides the Company's Lead-Lag study.
- *Mr. Todd Diggins, UES's Treasurer and Director of Finance,* supports the Company's proposed capital structure, explains the importance of maintaining UES's financial strength and integrity, and supports the Company's petition for a waiver to change its existing short-term debt formula.

- *Ms. Sara Sankowich, Director of Sustainability and Shared Services*, discusses UES's ongoing Vegetation Management Program.
- *Ms. Carole Beaulieu, Sales, Customer Service and Credit Manager*, discusses the Company's proposed Arrearage Management Program.
- *Mr. Jonathan Giegerich, Tax Manager*, describes the effects of the Tax Cuts and Jobs Act of 2017 on UES's accounting for income taxes and how those effects are presented in the current rate case cost of service schedules.
- *Mr. John Taylor of Atrium Economics* supports the Company's rate design proposals including new LED Lighting rates, the Domestic time of use rate and time of use rates for electric vehicle charging.
- *Mr. Ronald Amen of Atrium Economics* presents the Company's allocated cost of service, and marginal cost of service studies, and revenue apportionment and revenue targets by rate class.
- *Mr. Timothy Lyons, Partner, ScottMadden, Inc.* provides the Company's proposed revenue decoupling structure.
- *Ms. Jennifer Nelson, Assistant Vice President, Concentric Energy Advisors*, presents analyses supporting the investor-required Return on Equity reflected in the Company's revenue requirement.
- *Mr. Ned Allis, Vice President, Gannett Fleming* presents the depreciation study used to establish the annual depreciation rates for the Company's electric utility plant.

VII. <u>SUMMARY AND CONCLUSIONS</u>

Q. Please now summarize your testimony.

A. Over the past several years, the Company has focused on delivering safe, reliable, and affordable energy service while investing in the assets that will enable the advanced electric distribution system our stakeholders expect. We are proud of our past accomplishments and we look forward to further supporting New Hampshire's energy policy objectives. The multi-year plan we propose in this application will allow UES to continue investing in the assets needed to provide the enhanced services and reliability our customers require, and the rate mechanisms we propose will ensure just and reasonable rates.

We look forward to discussing this proposal with our stakeholders, and to working collaboratively with them on the important public policy issues that lie ahead. And we are confident that with a constructive outcome in this proceeding, our stakeholders' shared interests in safe, reliable, clean, and affordable electricity delivered by a stable, financially healthy utility will be well-served.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

Bob Hevert is a financial and economic professional with more than 30 years of broad experience in the energy and utility industries. He has an extensive background in the areas of corporate finance, mergers and acquisitions, project finance, asset and business unit valuation, rate and regulatory matters, energy market assessment, and corporate strategic planning. He has provided expert testimony on a wide range of financial, strategic, and economic matters on nearly 300 occasions at the state, provincial, and federal levels.

Prior to joining Unitil Corporation, Bob served as a Partner and Practice Area Leader at ScottMadden, Inc., Managing Partner at Sussex Economic Advisors, LLC, President of Concentric Energy Advisors, Inc., and Vice President and Assistant Treasurer of Bay State Gas Company. Throughout the course of his career, he has worked with numerous leading energy companies and financial institutions throughout North America.

Bob earned a B.S. in business and economics from the University of Delaware, and an M.B.A. with a concentration in finance from the University of Massachusetts at Amherst. Bob also holds the Chartered Financial Analyst designation.

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Regulatory Commission of Alaska				
Cook Inlet Natural Gas Storage Alaska, LLC	06/18	Cook Inlet Natural Gas Storage Alaska, LLC	Docket No. U-18-043	Return on Equity
ENSTAR Natural Gas Company	06/16	ENSTAR Natural Gas Company	Matter No. TA 285-4	Return on Equity
ENSTAR Natural Gas Company	08/14	ENSTAR Natural Gas Company	Matter No. TA 262-4	Return on Equity
Alberta Utilities Commission				
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	01/20	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	2021 Generic Cost of Capital, Proceeding ID. 24110	Rate of Return
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc., and FortisAlberta Inc.	10/17	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc., and FortisAlberta Inc.	2018 Generic Cost of Capital, Proceeding ID. 22570	Rate of Return
EPCOR Energy Alberta G.P. Inc.	01/17	EPCOR Energy Alberta G.P. Inc.	Proceeding 22357	Energy Price Setting Plan
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	02/16	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	2016 Generic Cost of Capital, Proceeding ID. 20622	Rate of Return
Arizona Corporation Commission				
Southwest Gas Corporation	05/19	Southwest Gas Corporation	Docket No. G-01551A-19-0055	Return on Equity
Southwest Gas Corporation	05/16	Southwest Gas Corporation	Docket No. G-01551A-16-0107	Return on Equity
Southwest Gas Corporation	11/10	Southwest Gas Corporation	Docket No. G-01551A-10-0458	Return on Equity
Arkansas Public Service Commission				
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	07/19	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	Docket No. 17-010-FR	Response to Direct Testimony of Staff Witness regarding Cost of Long Term Debt for Formula Rate Plan Rider
Southwestern Electric Power Company	02/19	Southwestern Electric Power Company	Docket No. 19-008-U	Return on Equity
Oklahoma Gas and Electric Company	09/16	Oklahoma Gas and Electric Company	Docket No. 16-052-U	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
SourceGas Arkansas, Inc.	12/15	SourceGas Arkansas, Inc.	Docket No. 15-078-U	Response to Direct Testimony by Arkansas Attorney General related to Compliance Issues
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	11/15	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	Docket No. 15-098-U	Return on Equity
SourceGas Arkansas, Inc.	04/15	SourceGas Arkansas, Inc.	Docket No. 15-011-U	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	01/07	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	Docket No. 06-161-U	Return on Equity
California Public Utilities Commission				
Southwest Gas Corporation	08/19	Southwest Gas Corporation	Docket No. A-19-08-015	Return on Equity
Southwest Gas Corporation	12/12	Southwest Gas Corporation	Docket No. A-12-12-024	Return on Equity
Colorado Public Utilities Commission				
Atmos Energy Corporation	06/17	Atmos Energy Corporation	Docket No. 17AL-0429G	Return on Equity
Xcel Energy, Inc.	03/15	Public Service Company of Colorado	Docket No. 15AL-0135G	Return on Equity (gas)
Xcel Energy, Inc.	06/14	Public Service Company of Colorado	Docket No. 14AL-0660E	Return on Equity (electric)
Xcel Energy, Inc.	12/12	Public Service Company of Colorado	Docket No. 12AL-1268G	Return on Equity (gas)
Xcel Energy, Inc.	11/11	Public Service Company of Colorado	Docket No. 11AL-947E	Return on Equity (electric)
Xcel Energy, Inc.	12/10	Public Service Company of Colorado	Docket No. 10AL-963G	Return on Equity (electric)
Atmos Energy Corporation	07/09	Atmos Energy Colorado-Kansas Division	Docket No. 09AL-507G	Return on Equity (gas)
Xcel Energy, Inc.	12/06	Public Service Company of Colorado	Docket No. 06S-656G	Return on Equity (gas)
Xcel Energy, Inc.	04/06	Public Service Company of Colorado	Docket No. 06S-234EG	Return on Equity (electric)
Xcel Energy, Inc.	08/05	Public Service Company of Colorado	Docket No. 05S-369ST	Return on Equity (steam)
Xcel Energy, Inc.	05/05	Public Service Company of Colorado	Docket No. 05S-246G	Return on Equity (gas)
Connecticut Public Utilities Regulatory Authority				
Connecticut Light and Power Company	11/17	Connecticut Light and Power Company	Docket No. 17-10-46	Return on Equity
Connecticut Light and Power Company	06/14	Connecticut Light and Power Company	Docket No. 14-05-06	Return on Equity
Southern Connecticut Gas Company	09/08	Southern Connecticut Gas Company	Docket No. 08-08-17	Return on Equity
Southern Connecticut Gas Company	12/07	Southern Connecticut Gas Company	Docket No. 05-03-17PH02	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Connecticut Natural Gas Corporation	12/07	Connecticut Natural Gas Corporation	Docket No. 06-03-04PH02	Return on Equity
Council of the City of New Orleans				
Entergy New Orleans, LLC	09/18	Entergy New Orleans, LLC	Docket No. UD-18-07	Return on Equity
Delaware Public Service Commission				
Delmarva Power & Light Company	03/20	Delmarva Power & Light Company	Docket No. 20-0149 (Electric)	Return on Equity
Delmarva Power & Light Company	02/20	Delmarva Power & Light Company	Docket No. 20-0150 (Gas)	Return on Equity
Delmarva Power & Light Company	08/17	Delmarva Power & Light Company	Docket No. 17-0977 (Electric)	Return on Equity
Delmarva Power & Light Company	08/17	Delmarva Power & Light Company	Docket No. 17-0978 (Gas)	Return on Equity
Delmarva Power & Light Company	05/16	Delmarva Power & Light Company	Case No. 16-649 (Electric)	Return on Equity
Delmarva Power & Light Company	05/16	Delmarva Power & Light Company	Case No. 16-650 (Gas)	Return on Equity
Delmarva Power & Light Company	03/13	Delmarva Power & Light Company	Case No. 13-115	Return on Equity
Delmarva Power & Light Company	12/12	Delmarva Power & Light Company	Case No. 12-546	Return on Equity
Delmarva Power & Light Company	03/12	Delmarva Power & Light Company	Case No. 11-528	Return on Equity
District of Columbia Public Service Commission				
Washington Gas Light Company	01/20	Washington Gas Light Company	Formal Case No. 1162	Return on Equity
Potomac Electric Power Company	05/19	Potomac Electric Power Company	Formal Case No. 1156	Return on Equity
Potomac Electric Power Company	12/17	Potomac Electric Power Company	Formal Case No. 1150	Return on Equity
Potomac Electric Power Company	06/16	Potomac Electric Power Company	Formal Case No. 1139	Return on Equity
Washington Gas Light Company	02/16	Washington Gas Light Company	Formal Case No. 1137	Return on Equity
Potomac Electric Power Company	03/13	Potomac Electric Power Company	Formal Case No. 1103-2013-E	Return on Equity
Potomac Electric Power Company	07/11	Potomac Electric Power Company	Formal Case No. 1087	Return on Equity
Federal Energy Regulatory Commission				
Potomac-Appalachian Transmission Highline, LLC	05/20	Potomac-Appalachian Transmission Highline, LLC	Docket Nos. ER09-1256-003 & ER09-1256-005	Declaration explaining why the FERC should also consider Expected Earnings & Risk Premium models when setting Returns on Equity
LS Power Grid New York Corporation I	12/19	LS Power Grid New York Corporation I	Docket No. ER20-716-000	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Duke Energy Progress, LLC	11/19	Duke Energy Progress	Docket No. EL20-4-000	Answer testimony to Complainant Affidavit from Mr. Mac Mathuna regarding Return on Equity applied in the FRPPA
Edison Electric Institute	07/19	Edison Electric Institute	Docket No. PL19-4-000	Reply comments to FERC Notice of Inquiry regarding Return on Equity analysis
Sabine Pipeline, LLC	09/15	Sabine Pipeline, LLC	Docket No. RP15-1322-000	Return on Equity
NextEra Energy Transmission West, LLC	07/15	NextEra Energy Transmission West, LLC	Docket No. ER15-2239-000	Return on Equity
Maritimes & Northeast Pipeline, LLC	05/15	Maritimes & Northeast Pipeline, LLC	Docket No. RP15-1026-000	Return on Equity
Public Service Company of New Mexico	12/12	Public Service Company of New Mexico	Docket No. ER13-685-000	Return on Equity
Public Service Company of New Mexico	10/10	Public Service Company of New Mexico	Docket No. ER11-1915-000	Return on Equity
Portland Natural Gas Transmission System	05/10	Portland Natural Gas Transmission System	Docket No. RP10-729-000	Return on Equity
Florida Gas Transmission Company, LLC	10/09	Florida Gas Transmission Company, LLC	Docket No. RP10-21-000	Return on Equity
Maritimes and Northeast Pipeline, LLC	07/09	Maritimes and Northeast Pipeline, LLC	Docket No. RP09-809-000	Return on Equity
Spectra Energy	02/08	Saltville Gas Storage	Docket No. RP08-257-000	Return on Equity
Panhandle Energy Pipelines	08/07	Panhandle Energy Pipelines	Docket No. PL07-2-000	Response to draft policy statement regarding inclusion of MLPs in proxy groups for determination of gas pipeline ROEs
Southwest Gas Storage Company	08/07	Southwest Gas Storage Company	Docket No. RP07-541-000	Return on Equity
Southwest Gas Storage Company	06/07	Southwest Gas Storage Company	Docket No. RP07-34-000	Return on Equity
Sea Robin Pipeline LLC	06/07	Sea Robin Pipeline LLC	Docket No. RP07-513-000	Return on Equity
Transwestern Pipeline Company	09/06	Transwestern Pipeline Company	Docket No. RP06-614-000	Return on Equity

Sponsor	Date	Case/Applicant	Docket No.	Subject
GPU International and Aquila	11/00	GPU International	Docket No. EC01-24-000	Market Power Study
Florida Public Service Commission				
TECO Peoples Gas	06/20	Peoples Gas System	Docket No. 20200051-GU	Return on Equity
Florida Power & Light Company	03/16	Florida Power & Light Company	Docket No. 160021-EI	Return on Equity
Tampa Electric Company	04/13	Tampa Electric Company	Docket No. 130040-EI	Return on Equity
Georgia Public Service Commission				
Atlanta Gas Light Company	05/10	Atlanta Gas Light Company	Docket No. 31647-U	Return on Equity
Hawaii Public Utilities Commission				
Hawaiian Electric Company, Inc.	08/19	Hawaiian Electric Company, Inc.	Docket No. 2019-0085	Return on Equity
Hawai‘i Electric Light Company, Inc.	12/18	Hawai‘i Electric Light Company, Inc.	Docket No. 2018-0368	Return on Equity
Maui Electric Company, Limited	10/17	Maui Electric Company, Limited	Docket No. 2017-0150	Return on Equity
Hawaiian Electric Company, Inc.	12/16	Hawaiian Electric Company, Inc.	Docket No. 2016-0328	Return on Equity
Hawai‘i Electric Light Company, Inc.	09/16	Hawai‘i Electric Light Company, Inc.	Docket No. 2015-0170	Return on Equity
Maui Electric Company, Limited	12/14	Maui Electric Company, Limited	Docket No. 2014-0318	Return on Equity
Hawaiian Electric Company, Inc.	06/14	Hawaiian Electric Company, Inc.	Docket No. 2013-0373	Return on Equity
Hawai’i Electric Light Company, Inc.	08/12	Hawai’i Electric Light Company, Inc.	Docket No. 2012-0099	Return on Equity
Illinois Commerce Commission				
Ameren Illinois Company d/b/a Ameren Illinois	02/20	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 20-0308	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	01/18	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 18-0463	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	01/15	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 15-0142	Return on Equity
Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	04/14	Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	Docket No. 14-0371	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	01/13	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 13-0192	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	02/11	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 11-0279	Return on Equity (electric)

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Ameren Illinois Company d/b/a Ameren Illinois	02/11	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 11-0282	Return on Equity (gas)
Indiana Utility Regulatory Commission				
Duke Energy Indiana, Inc.	07/19	Duke Energy Indiana, Inc.	Cause No. 45253	Return on Equity
Indiana Michigan Power Company	05/19	Indiana Michigan Power Company	Cause No. 45235	Return on Equity
Indiana Michigan Power Company	07/17	Indiana Michigan Power Company	Cause No. 44967	Return on Equity
Duke Energy Indiana, Inc.	12/15	Duke Energy Indiana, Inc.	Cause No. 44720	Return on Equity
Duke Energy Indiana, Inc.	12/14	Duke Energy Indiana, Inc.	Cause No. 44526	Return on Equity
Northern Indiana Public Service Company	05/09	Northern Indiana Public Service Company	Cause No. 43894	Assessment of Valuation Approaches
Kansas Corporation Commission				
Empire District Electric Company	02/19	Empire District Electric Company	Docket No. 19-EPDE-223-RTS	Return on Equity
Empire District Electric Company	12/18	Empire District Electric Company	Docket No. 19-EPDE-223-RTS	Alternative Ratemaking Mechanisms
Kansas City Power & Light Company	05/18	Kansas City Power & Light Company	Docket No. 18-KCPE-480-RTS	Return on Equity
Westar Energy	02/18	Westar Energy	Docket No. 18-WSEE-328-RTS	Return on Equity
Great Plains Energy, Inc. and Kansas City Power & Light Company	01/17	Great Plains Energy, Inc. and Kansas City Power & Light Company	Docket No. 16-KCPE-593-ACQ	Response to Direct Testimony by Commission Staff related to the ratemaking capital structure processes
Kansas City Power & Light Company	01/15	Kansas City Power & Light Company	Docket No. 15-KCPE-116-RTS	Return on Equity
Maine Public Utilities Commission				
Northern Utilities, Inc.	06/19	Northern Utilities, Inc.	Docket No. 2019-00092	Return on Equity
Northern Utilities, Inc.	05/17	Northern Utilities, Inc.	Docket No. 2017-00065	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Central Maine Power Company	06/11	Central Maine Power Company	Docket No. 2010-327	Response to Bench Analysis provided by Commission Staff relating to the Company's credit and collections processes
Maryland Public Service Commission				
Delmarva Power & Light Company	12/19	Delmarva Power & Light Company	Case No. 9630	Return on Equity
Washington Gas Light Company	04/19	Washington Gas Light Company	Case No. 9605	Return on Equity
Potomac Electric Power Company	01/19	Potomac Electric Power Company	Case No. 9602	Return on Equity
Washington Gas Light Company	05/18	Washington Gas Light Company	Case No. 9481	Return on Equity
Potomac Electric Power Company	01/18	Potomac Electric Power Company	Case No. 9472	Return on Equity
Delmarva Power & Light Company	07/17	Delmarva Power & Light Company	Case No. 9455	Return on Equity
Potomac Electric Power Company	03/17	Potomac Electric Power Company	Case No. 9443	Return on Equity
Delmarva Power & Light Company	06/16	Delmarva Power & Light Company	Case No. 9424	Return on Equity
Potomac Electric Power Company	06/16	Potomac Electric Power Company	Case No. 9418	Return on Equity
Potomac Electric Power Company	12/13	Potomac Electric Power Company	Case No. 9336	Return on Equity
Delmarva Power & Light Company	03/13	Delmarva Power & Light Company	Case No. 9317	Return on Equity
Potomac Electric Power Company	11/12	Potomac Electric Power Company	Case No. 9311	Return on Equity
Potomac Electric Power Company	12/11	Potomac Electric Power Company	Case No. 9286	Return on Equity
Delmarva Power & Light Company	12/11	Delmarva Power & Light Company	Case No. 9285	Return on Equity
Delmarva Power & Light Company	12/10	Delmarva Power & Light Company	Case No. 9249	Return on Equity
Massachusetts Department of Public Utilities				
NSTAR Electric Company d/b/a Eversource Energy; Massachusetts Electric Company & Nantucket Electric Company, d/b/a National Grid; and Fitchburg Gas and Electric Light Company, d/b/a Unitil	02/20	NSTAR Electric Company d/b/a Eversource Energy; Massachusetts Electric Company & Nantucket Electric Company, d/b/a National Grid; and Fitchburg Gas and Electric Light Company, d/b/a Unitil	DPU 20-16/DPU 20-17/DPU 20-18	In Support of Request for Financial Remuneration
NSTAR Gas Company d/b/a Eversource Energy	11/19	NSTAR Gas Company d/b/a Eversource Energy	DPU 19-120	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
NSTAR Electric Company d/b/a Eversource Energy; Massachusetts Electric Company & Nantucket Electric Company, d/b/a National Grid; and Fitchburg Gas and Electric Light Company, d/b/a Unitil	02/19	NSTAR Electric Company d/b/a Eversource Energy; Massachusetts Electric Company & Nantucket Electric Company, d/b/a National Grid; and Fitchburg Gas and Electric Light Company, d/b/a Unitil	DPU 18-64/DPU 18-65/DPU 18-66	Response to Direct Testimony by Attorney General Witness regarding Remuneration Rate Section 83D
National Grid	11/18	Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid	DPU 18-150	Return on Equity
NSTAR Electric Company d/b/a Eversource Energy	11/18	NSTAR Electric Company d/b/a Eversource Energy	DPU 18-76/DPU 18-77/DPU 18-78	Response to Direct Testimony by Attorney General Witness regarding Remuneration Rate Section 83C
Boston Gas Company, Colonial Gas Company each d/b/a National Grid	11/17	Boston Gas Company, Colonial Gas Company each d/b/a National Grid	DPU 17-170	Return on Equity
NSTAR Electric Company Western and Massachusetts Electric Company each d/b/a Eversource Energy	01/17	NSTAR Electric Company Western Massachusetts Electric Company each d/b/a Eversource Energy	DPU 17-05	Return on Equity
National Grid	11/15	Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid	DPU 15-155	Return on Equity
Fitchburg Gas and Electric Light Company d/b/a Unitil	06/15	Fitchburg Gas and Electric Light Company d/b/a Unitil	DPU 15-80	Return on Equity
NSTAR Gas Company	12/14	NSTAR Gas Company	DPU 14-150	Return on Equity
Fitchburg Gas and Electric Light Company d/b/a Unitil	07/13	Fitchburg Gas and Electric Light Company d/b/a Unitil	DPU 13-90	Return on Equity
Bay State Gas Company d/b/a Columbia Gas of Massachusetts	04/12	Bay State Gas Company d/b/a Columbia Gas of Massachusetts	DPU 12-25	Capital Cost Recovery
National Grid	08/09	Massachusetts Electric Company d/b/a National Grid	DPU 09-39	Revenue Decoupling and Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
National Grid	08/09	Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid	DPU 09-38	Return on Equity – Solar Generation
Bay State Gas Company	04/09	Bay State Gas Company	DPU 09-30	Return on Equity
NSTAR Electric	09/04	NSTAR Electric	DTE 04-85	Divestiture of Power Purchase Agreement
NSTAR Electric	08/04	NSTAR Electric	DTE 04-78	Divestiture of Power Purchase Agreement
NSTAR Electric	07/04	NSTAR Electric	DTE 04-68	Divestiture of Power Purchase Agreement
NSTAR Electric	07/04	NSTAR Electric	DTE 04-61	Divestiture of Power Purchase Agreement
NSTAR Electric	06/04	NSTAR Electric	DTE 04-60	Divestiture of Power Purchase Agreement
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Bay State Gas Company	01/93	Bay State Gas Company	DPU 93-14	Divestiture of Shelf Registration
Bay State Gas Company	01/91	Bay State Gas Company	DPU 91-25	Divestiture of Shelf Registration
Michigan Public Service Commission				
Indiana Michigan Power Company	06/19	Indiana Michigan Power Company	Case No. U-20359	Return on Equity
SEMCO Energy Gas Company	05/19	SEMCO Energy Gas Company	Case No. U-20479	Return on Equity
Indiana Michigan Power Company	05/17	Indiana Michigan Power Company	Case No. U-18370	Return on Equity
Minnesota Public Utilities Commission				
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	08/17	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-17-285	Return on Equity
ALLETE, Inc., d/b/a Minnesota Power Inc.	11/16	ALLETE, Inc., d/b/a Minnesota Power Inc.	Docket No. E015/GR-16-664	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Otter Tail Power Corporation	02/16	Otter Tail Power Company	Docket No. E017/GR-15-1033	Return on Equity
Minnesota Energy Resources Corporation	09/15	Minnesota Energy Resources Corporation	Docket No. G-011/GR-15-736	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	08/15	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-15-424	Return on Equity
Xcel Energy, Inc.	11/13	Northern States Power Company	Docket No. E002/GR-13-868	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	08/13	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-13-316	Return on Equity
Xcel Energy, Inc.	11/12	Northern States Power Company	Docket No. E002/GR-12-961	Return on Equity
Otter Tail Power Corporation	04/10	Otter Tail Power Company	Docket No. E-017/GR-10-239	Return on Equity
Minnesota Power a division of ALLETE, Inc.	11/09	Minnesota Power	Docket No. E-015/GR-09-1151	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	11/08	CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-08-1075	Return on Equity
Otter Tail Power Corporation	10/07	Otter Tail Power Company	Docket No. E-017/GR-07-1178	Return on Equity
Xcel Energy, Inc.	11/05	Northern States Power Company - Minnesota	Docket No. E-002/GR-05-1428	Return on Equity (electric)
Xcel Energy, Inc.	09/04	Northern States Power Company - Minnesota	Docket No. G-002/GR-04-1511	Return on Equity (gas)
Mississippi Public Service Commission				
CenterPoint Energy Resources, Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Mississippi Gas	07/09	CenterPoint Energy Mississippi Gas	Docket No. 09-UN-334	Return on Equity
Missouri Public Service Commission				
Empire District Electric Company	08/19	Empire District Electric Company	Case No. ER-2019-0374	Return on Equity
Union Electric Company d/b/a Ameren Missouri	07/19	Union Electric Company d/b/a Ameren Missouri	Case No. ER-2019-0335	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Union Electric Company d/b/a Ameren Missouri	12/18	Union Electric Company d/b/a Ameren Missouri	Case No. GR-2019-0077	Return on Equity
KCP&L Greater Missouri Operations Company	01/18	KCP&L Greater Missouri Operations Company	Case No. ER-2018-0146	Return on Equity
Kansas City Power & Light Company	01/18	Kansas City Power & Light Company	Case No. ER-2018-0145	Return on Equity
Laclede Gas Company and Missouri Gas Energy	11/17	Laclede Gas Company and Missouri Gas Energy	Case No. GR-2017-0215 Case No. GR-2017-0216	Goodwill Adjustment on Capital Structure
Liberty Utilities (Midstates Natural Gas) Corp. d/b/a/ Liberty Utilities	09/17	Liberty Utilities (Midstates Natural Gas) Corp. d/b/a/ Liberty Utilities	Case No. GR-2018-0013	New Ratemaking Mechanisms
Union Electric Company d/b/a Ameren Missouri	07/16	Union Electric Company d/b/a Ameren Missouri	Case No. ER-2016-0179	Return on Equity (electric)
Kansas City Power & Light Company	07/16	Kansas City Power & Light Company	Case No. ER-2016-0285	Return on Equity (electric)
Kansas City Power & Light Company	02/16	Kansas City Power & Light Company	Case No. ER-2016-0156	Return on Equity (electric)
Kansas City Power & Light Company	10/14	Kansas City Power & Light Company	Case No. ER-2014-0370	Return on Equity (electric)
Union Electric Company d/b/a Ameren Missouri	07/14	Union Electric Company d/b/a Ameren Missouri	Case No. ER-2014-0258	Return on Equity (electric)
Union Electric Company d/b/a Ameren Missouri	06/14	Union Electric Company d/b/a Ameren Missouri	Case No. EC-2014-0223	Return on Equity (electric)
Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	02/14	Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	Case No. GR-2014-0152	Return on Equity
Laclede Gas Company	12/12	Laclede Gas Company	Case No. GR-2013-0171	Return on Equity
Union Electric Company d/b/a Ameren Missouri	02/12	Union Electric Company d/b/a Ameren Missouri	Case No. ER-2012-0166	Return on Equity (electric)
Union Electric Company d/b/a AmerenUE	09/10	Union Electric Company d/b/a AmerenUE	Case No. ER-2011-0028	Return on Equity (electric)
Union Electric Company d/b/a AmerenUE	06/10	Union Electric Company d/b/a AmerenUE	Case No. GR-2010-0363	Return on Equity (gas)
Montana Public Service Commission				
Northwestern Corporation	09/12	Northwestern Corporation d/b/a Northwestern Energy	Docket No. D2012.9.94	Return on Equity (gas)

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Nevada Public Utilities Commission				
Southwest Gas Corporation	02/20	Southwest Gas Corporation	Docket No. 20-02023	Return on Equity (gas)
Southwest Gas Corporation	05/18	Southwest Gas Corporation	Docket No. 18-05031	Return on Equity (gas)
Southwest Gas Corporation	04/12	Southwest Gas Corporation	Docket No. 12-04005	Return on Equity (gas)
Nevada Power Company	06/11	Nevada Power Company	Docket No. 11-06006	Return on Equity (electric)
New Hampshire Public Utilities Commission				
Northern Utilities, Inc.	06/17	Northern Utilities, Inc.	Docket No. DG 17-070	Return on Equity
Liberty Utilities d/b/a EnergyNorth Natural Gas	04/17	Liberty Utilities d/b/a EnergyNorth Natural Gas	Docket No. DG 17-048	Return on Equity
Unitil Energy Systems, Inc.	04/16	Unitil Energy Systems, Inc.	Docket No. DE 16-384	Return on Equity
Liberty Utilities d/b/a Granite State Electric Company	04/16	Liberty Utilities d/b/a Granite State Electric Company	Docket No. DE 16-383	Return on Equity
Liberty Utilities d/b/a EnergyNorth Natural Gas	08/14	Liberty Utilities d/b/a EnergyNorth Natural Gas	Docket No. DG 14-180	Return on Equity
Liberty Utilities d/b/a Granite State Electric Company	03/13	Liberty Utilities d/b/a Granite State Electric Company	Docket No. DE 13-063	Return on Equity
EnergyNorth Natural Gas d/b/a National Grid NH	02/10	EnergyNorth Natural Gas d/b/a National Grid NH	Docket No. DG 10-017	Return on Equity
Unitil Energy Systems, Inc., EnergyNorth Natural Gas, Inc. d/b/a National Grid NH, Granite State Electric Company d/b/a National Grid, and Northern Utilities, Inc. – New Hampshire Division	08/08	Unitil Energy Systems, Inc., EnergyNorth Natural Gas, Inc. d/b/a National Grid NH, Granite State Electric Company d/b/a National Grid, and Northern Utilities, Inc. – New Hampshire Division	Docket No. DG 07-072	Carrying Charge Rate on Cash Working Capital
New Jersey Board of Public Utilities				
South Jersey Gas Company	03/20	South Jersey Gas Company	Docket No. GR20030243	Return on Equity
Elizabethtown Gas Company	04/19	Elizabethtown Gas Company	Docket No. GR19040486	Return on Equity
Atlantic City Electric Company	10/18	Atlantic City Electric Company	Docket No. EO18020196	Return on Equity
Atlantic City Electric Company	08/18	Atlantic City Electric Company	Docket No. ER18080925	Return on Equity
Atlantic City Electric Company	06/18	Atlantic City Electric Company	Docket No. ER18060638	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Atlantic City Electric Company	03/17	Atlantic City Electric Company	Docket No. ER17030308	Return on Equity
Pivotal Utility Holdings, Inc.	08/16	Elizabethtown Gas	Docket No. GR16090826	Return on Equity
The Southern Company; AGL Resources Inc.; AMS Corp. and Pivotal Holdings, Inc. d/b/a Elizabethtown Gas	04/16	The Southern Company; AGL Resources Inc.; AMS Corp. and Pivotal Holdings, Inc. d/b/a Elizabethtown Gas	Docket No. GM15101196	Merger Approval
Atlantic City Electric Company	03/16	Atlantic City Electric Company	Docket No. ER16030252	Return on Equity
Pepco Holdings, Inc.	03/14	Atlantic City Electric Company	Docket No. ER14030245	Return on Equity
Orange and Rockland Utilities	11/13	Rockland Electric Company	Docket No. ER13111135	Return on Equity
Atlantic City Electric Company	12/12	Atlantic City Electric Company	Docket No. ER12121071	Return on Equity
Atlantic City Electric Company	08/11	Atlantic City Electric Company	Docket No. ER11080469	Return on Equity
Pepco Holdings, Inc.	09/06	Atlantic City Electric Company	Docket No. EM06090638	Divestiture and Valuation of Electric Generating Assets
Pepco Holdings, Inc.	12/05	Atlantic City Electric Company	Docket No. EM05121058	Market Value of Electric Generation Assets; Auction
Conectiv	06/03	Atlantic City Electric Company	Docket No. EO03020091	Market Value of Electric Generation Assets; Auction Process
New Mexico Public Regulation Commission				
El Paso Electric Company	05/20	El Paso Electric Company	Case No. 20-00104-UT	Return on Equity
Public Service Company of New Mexico	12/16	Public Service Company of New Mexico	Case No. 16-00276-UT	Return on Equity (electric)
Public Service Company of New Mexico	08/15	Public Service Company of New Mexico	Case No. 15-00261-UT	Return on Equity (electric)
Public Service Company of New Mexico	12/14	Public Service Company of New Mexico	Case No. 14-00332-UT	Return on Equity (electric)
Public Service Company of New Mexico	12/14	Public Service Company of New Mexico	Case No. 13-00390-UT	Cost of Capital and Financial Integrity
Southwestern Public Service Company	02/11	Southwestern Public Service Company	Case No. 10-00395-UT	Return on Equity (electric)
Public Service Company of New Mexico	06/10	Public Service Company of New Mexico	Case No. 10-00086-UT	Return on Equity (electric)

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Public Service Company of New Mexico	09/08	Public Service Company of New Mexico	Case No. 08-00273-UT	Return on Equity (electric)
Xcel Energy, Inc.	07/07	Southwestern Public Service Company	Case No. 07-00319-UT	Return on Equity (electric)
New York State Public Service Commission				
Consolidated Edison Company of New York, Inc.	01/15	Consolidated Edison Company of New York, Inc.	Case No. 15-E-0050	Return on Equity (electric)
Orange and Rockland Utilities, Inc.	11/14	Orange and Rockland Utilities, Inc.	Case Nos. 14-E-0493 and 14-G-0494	Return on Equity (electric and gas)
Consolidated Edison Company of New York, Inc.	01/13	Consolidated Edison Company of New York, Inc.	Case No. 13-E-0030	Return on Equity (electric)
Niagara Mohawk Corporation d/b/a National Grid for Electric Service	04/12	Niagara Mohawk Corporation d/b/a National Grid for Electric Service	Case No. 12-E-0201	Return on Equity (electric)
Niagara Mohawk Corporation d/b/a National Grid for Gas Service	04/12	Niagara Mohawk Corporation d/b/a National Grid for Gas Service	Case No. 12-G-0202	Return on Equity (gas)
Orange and Rockland Utilities, Inc.	07/11	Orange and Rockland Utilities, Inc.	Case No. 11-E-0408	Return on Equity (electric)
Orange and Rockland Utilities, Inc.	07/10	Orange and Rockland Utilities, Inc.	Case No. 10-E-0362	Return on Equity (electric)
Consolidated Edison Company of New York, Inc.	11/09	Consolidated Edison Company of New York, Inc.	Case No. 09-G-0795	Return on Equity (gas)
Consolidated Edison Company of New York, Inc.	11/09	Consolidated Edison Company of New York, Inc.	Case No. 09-S-0794	Return on Equity (steam)
Niagara Mohawk Power Corporation	07/01	Niagara Mohawk Power Corporation	Case No. 01-E-1046	Power Purchase and Sale Agreement; Standard Offer Service Agreement
North Carolina Utilities Commission				
Duke Energy Progress, LLC	10/19	Duke Energy Progress, LLC	Docket No. E-2, Sub 1219	Return on Equity
Duke Energy Carolinas, LLC	09/19	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1214	Return on Equity
Piedmont Natural Gas Company, Inc.	04/19	Piedmont Natural Gas Company, Inc.	Docket No. G-9, Sub 743	Return on Equity
Virginia Electric and Power Company d/b/a Dominion North Carolina Power	03/19	Virginia Electric and Power Company d/b/a Dominion North Carolina Power	Docket No. E-22, Sub 562	Return on Equity
Duke Energy Carolinas, LLC	08/17	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1146	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Duke Energy Progress, LLC	06/17	Duke Energy Progress, LLC	Docket No. E-2, Sub 1142	Return on Equity
Public Service Company of North Carolina, Inc.	03/16	Public Service Company of North Carolina, Inc.	Docket No. G-5, Sub 565	Return on Equity
Dominion North Carolina Power	03/16	Dominion North Carolina Power	Docket No. E-22, Sub 532	Return on Equity
Duke Energy Carolinas, LLC	02/13	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1026	Return on Equity
Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.	10/12	Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.	Docket No. E-2, Sub 1023	Return on Equity
Virginia Electric and Power Company d/b/a Dominion North Carolina Power	03/12	Virginia Electric and Power Company d/b/a Dominion North Carolina Power	Docket No. E-22, Sub 479	Return on Equity
Duke Energy Carolinas, LLC	07/11	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 989	Return on Equity
North Dakota Public Service Commission				
Otter Tail Power Company	11/17	Otter Tail Power Company	Docket No. 17-398	Return on Equity (electric)
Otter Tail Power Company	11/08	Otter Tail Power Company	Docket No. 08-862	Return on Equity (electric)
Oklahoma Corporation Commission				
Empire District Electric Company	03/19	Empire District Electric Company	Cause No. PUD201800133	Return on Equity
CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Oklahoma Gas	03/16	CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Oklahoma Gas	Cause No. PUD201600094	Return on Equity
Oklahoma Gas & Electric Company	12/15	Oklahoma Gas & Electric Company	Cause No. PUD201500273	Return on Equity
Public Service Company of Oklahoma	07/15	Public Service Company of Oklahoma	Cause No. PUD201500208	Return on Equity
Oklahoma Gas & Electric Company	07/11	Oklahoma Gas & Electric Company	Cause No. PUD201100087	Return on Equity
CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Oklahoma Gas	03/09	CenterPoint Energy Oklahoma Gas	Cause No. PUD200900055	Return on Equity
Pennsylvania Public Utility Commission				
Pike County Light & Power Company	01/14	Pike County Light & Power Company	Docket No. R-2013-2397237	Return on Equity (electric & gas)
Veolia Energy Philadelphia, Inc.	12/13	Veolia Energy Philadelphia, Inc.	Docket No. R-2013-2386293	Return on Equity (steam)
Rhode Island Public Utilities Commission				
The Narragansett Electric Company d/b/a National Grid	02/19	The Narragansett Electric Company d/b/a National Grid	Docket No. 4929	Support for financial remuneration under new power purchase agreement

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
The Narragansett Electric Company d/b/a National Grid	11/17	The Narragansett Electric Company d/b/a National Grid	Docket No. 4770	Return on Equity (electric & gas)
The Narragansett Electric Company d/b/a National Grid	04/12	The Narragansett Electric Company d/b/a National Grid	Docket No. 4323	Return on Equity (electric & gas)
National Grid RI – Gas	08/08	National Grid RI – Gas	Docket No. 3943	Revenue Decoupling and Return on Equity
South Carolina Public Service Commission				
Duke Energy Carolinas, LLC	11/18	Duke Energy Carolinas, LLC	Docket No. 2018-319-E	Return on Equity
Duke Energy Progress, LLC	11/18	Duke Energy Progress, LLC	Docket No. 2018-318-E	Return on Equity
South Carolina Electric & Gas	08/18	South Carolina Electric & Gas	Docket No. 2017-370-E	Return on Equity
South Carolina Electric & Gas	12/17	South Carolina Electric & Gas	Docket No. 2017-305-E	Return on Equity
Duke Energy Progress, LLC	07/16	Duke Energy Progress, LLC	Docket No. 2016-227-E	Return on Equity
Duke Energy Carolinas, LLC	03/13	Duke Energy Carolinas, LLC	Docket No. 2013-59-E	Return on Equity
South Carolina Electric & Gas	06/12	South Carolina Electric & Gas	Docket No. 2012-218-E	Return on Equity
Duke Energy Carolinas, LLC	08/11	Duke Energy Carolinas, LLC	Docket No. 2011-271-E	Return on Equity
South Carolina Electric & Gas	03/10	South Carolina Electric & Gas	Docket No. 2009-489-E	Return on Equity
South Dakota Public Utilities Commission				
Otter Tail Power Company	04/18	Otter Tail Power Company	Docket No. EL18-021	Return on Equity (electric)
Otter Tail Power Company	08/10	Otter Tail Power Company	Docket No. EL10-011	Return on Equity (electric)
Northern States Power Company	06/09	South Dakota Division of Northern States Power	Docket No. EL09-009	Return on Equity (electric)
Otter Tail Power Company	10/08	Otter Tail Power Company	Docket No. EL08-030	Return on Equity (electric)
Texas Public Utility Commission				
AEP Texas, Inc.	05/19	AEP Texas, Inc.	Docket No. 49494	Return on Equity
CenterPoint Energy Houston Electric LLC	04/19	CenterPoint Energy Houston Electric LLC	Docket No. 49421	Return on Equity
Texas-New Mexico Power Company	05/18	Texas-New Mexico Power Company	Docket No. 48401	Return on Equity
Entergy Texas, Inc.	05/18	Entergy Texas, Inc.	Docket No. 48371	Return on Equity
Southwestern Public Service Company	08/17	Southwestern Public Service Company	Docket No. 47527	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Oncor Electric Delivery Company, LLC	03/17	Oncor Electric Delivery Company, LLC	Docket No. 46957	Return on Equity
El Paso Electric Company	02/17	El Paso Electric Company	Docket No. 46831	Return on Equity
Southwestern Electric Power Company	12/16	Southwestern Electric Power Company	Docket No. 46449	Return on Equity (electric)
Sharyland Utilities, L.P.	04/16	Sharyland Utilities, L.P.	Docket No. 45414	Return on Equity
Southwestern Public Service Company	02/16	Southwestern Public Service Company	Docket No. 44524	Return on Equity (electric)
Wind Energy Transmission Texas, LLC	05/15	Wind Energy Transmission Texas, LLC	Docket No. 44746	Return on Equity
Cross Texas Transmission	12/14	Cross Texas Transmission	Docket No. 43950	Return on Equity
Southwestern Public Service Company	12/14	Southwestern Public Service Company	Docket No. 43695	Return on Equity (electric)
Sharyland Utilities, L.P.	05/13	Sharyland Utilities, L.P.	Docket No. 41474	Return on Equity
Wind Energy Texas Transmission, LLC	08/12	Wind Energy Texas Transmission, LLC	Docket No. 40606	Return on Equity
Southwestern Electric Power Company	07/12	Southwestern Electric Power Company	Docket No. 40443	Return on Equity
Oncor Electric Delivery Company, LLC	01/11	Oncor Electric Delivery Company, LLC	Docket No. 38929	Return on Equity
Texas-New Mexico Power Company	08/10	Texas-New Mexico Power Company	Docket No. 38480	Return on Equity (electric)
CenterPoint Energy Houston Electric LLC	06/10	CenterPoint Energy Houston Electric LLC	Docket No. 38339	Return on Equity
Xcel Energy, Inc.	05/10	Southwestern Public Service Company	Docket No. 38147	Return on Equity (electric)
Texas-New Mexico Power Company	08/08	Texas-New Mexico Power Company	Docket No. 36025	Return on Equity (electric)
Xcel Energy, Inc.	05/06	Southwestern Public Service Company	Docket No. 32766	Return on Equity (electric)
Texas Railroad Commission				
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex And CenterPoint Energy Texas Gas	10/19	CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex And CenterPoint Energy Texas Gas	GUD 10920	Return on Equity
Atmos Energy Corporation – Mid-Tex Division	10/18	Atmos Energy Corporation – Mid-Tex Division	GUD 10779	Return on Equity
Atmos Energy Corporation – West Texas Division	06/18	Atmos Energy Corporation – West Texas Division	GUD 10743	Return on Equity
Atmos Energy Corporation – Mid-Texas Division	06/18	Atmos Energy Corporation – Mid-Texas Division	GUD 10742	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex And CenterPoint Energy Texas Gas	11/17	CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex And CenterPoint Energy Texas Gas	GUD 10669	Return on Equity
Atmos Pipeline - Texas	01/17	Atmos Pipeline - Texas	GUD 10580	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex And CenterPoint Energy Texas Gas	12/16	CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex And CenterPoint Energy Texas Gas	GUD 10567	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	03/15	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 10432	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	07/12	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 10182	Return on Equity
Atmos Energy Corporation – West Texas Division	06/12	Atmos Energy Corporation – West Texas Division	GUD 10174	Return on Equity
Atmos Energy Corporation – Mid-Texas Division	06/12	Atmos Energy Corporation – Mid-Texas Division	GUD 10170	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	12/10	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 10038	Return on Equity
Atmos Pipeline – Texas	09/10	Atmos Pipeline - Texas	GUD 10000	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	07/09	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 9902	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Texas Gas	03/08	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Texas Gas	GUD 9791	Return on Equity
Utah Public Service Commission				
Dominion Energy Utah	07/19	Dominion Energy Utah	Docket No. 19-057-02	Return on Equity
Questar Gas Company	12/07	Questar Gas Company	Docket No. 07-057-13	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Vermont Public Service Board				
Central Vermont Public Service Corporation; Green Mountain Power	02/12	Central Vermont Public Service Corporation; Green Mountain Power	Docket No. 7770	Merger Policy
Central Vermont Public Service Corporation	12/10	Central Vermont Public Service Corporation	Docket No. 7627	Return on Equity (electric)
Green Mountain Power	04/06	Green Mountain Power	Docket Nos. 7175 and 7176	Return on Equity (electric)
Vermont Gas Systems, Inc.	12/05	Vermont Gas Systems	Docket Nos. 7109 and 7160	Return on Equity (gas)
Virginia State Corporation Commission				
Virginia Natural Gas, Inc.	06/20	Virginia Natural Gas, Inc.	Case No. PUR-2020-00095	Return on Equity
Virginia Electric and Power Company	03/19	Virginia Electric and Power Company	Case No. PUR-2019-00050	Return on Equity
Virginia Electric and Power Company	03/17	Virginia Electric and Power Company	Case No. PUR-2017-00038	Return on Equity
Virginia Natural Gas, Inc.	03/17	Virginia Natural Gas, Inc.	Case No. PUE-2016-00143	Return on Equity
Virginia Electric and Power Company	10/16	Virginia Electric and Power Company	Case No. PUE-2016-00112; PUE-2016-00113; PUE-2016-00136	Return on Equity
Washington Gas Light Company	06/16	Washington Gas Light Company	Case No. PUE-2016-00001	Return on Equity
Virginia Electric and Power Company	06/16	Virginia Electric and Power Company	Case Nos. PUE-2016-00063; PUE-2016-00062; PUE-2016-00061; PUE-2016-00060; PUE-2016-00059	Return on Equity
Virginia Electric and Power Company	12/15	Virginia Electric and Power Company	Case Nos. PUE-2015-00058; PUE-2015-00059; PUE-2015-00060; PUE-2015-00061; PUE-2015-00075; PUE-2015-00089; PUE-2015-00102; PUE-2015-00104	Return on Equity
Virginia Electric and Power Company	03/15	Virginia Electric and Power Company	Case No. PUE-2015-00027	Return on Equity
Virginia Electric and Power Company	03/13	Virginia Electric and Power Company	Case No. PUE-2013-00020	Return on Equity
Virginia Natural Gas, Inc.	02/11	Virginia Natural Gas, Inc.	Case No. PUE-2010-00142	Capital Structure
Columbia Gas of Virginia, Inc.	06/06	Columbia Gas of Virginia, Inc.	Case No. PUE-2005-00098	Merger Synergies

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Dominion Resources	10/01	Virginia Electric and Power Company	Case No. PUE000584	Corporate Structure and Electric Generation Strategy
Wyoming Public Service Commission				
Questar Gas Company d/b/a Dominion Energy Wyoming	11/19	Questar Gas Company d/b/a Dominion Energy Wyoming	Docket No. 30010-187-GR-19	Return on Equity

Expert Reports

Matter of Arbitration, City of White Hall, Arkansas				
Liberty Utilities Corporation, White Hall Water and White Hall Sewer	04/19	Liberty Utilities Corporation, White Hall Water and White Hall Sewer	AAA Case No. 01-18-0004-0072	Return on Equity
United States District Court, District of South Carolina, Columbia Division				
South Carolina Electric & Gas Company	07/18	South Carolina Electric & Gas Company	Case No. 3:18-CV-01795-JMC	Return on Equity
United States District Court, Western District of Texas, Austin Division				
Southwestern Public Service Company	02/12	Southwestern Public Service Company	C.A. No. A-09-CA-917-SS	PURPA and FERC regulations
U.S. Court of Federal Claims				
Confidential Client	07/06	Confidential Client	Confidential Client	Economic harm related to breach of contract
American Arbitration Association				
Confidential Client	11/14	Confidential Client	Confidential	Economic harm related to failure to perform

[THIS PAGE INTENTIONALLY LEFT BLANK]

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY

OF

CHRISTOPHER J. GOULDING

AND

DANIEL T. NAWAZELSKI

EXHIBIT CGDN-1

New Hampshire Public Utilities Commission

Docket No. DE 21-030

Table of Contents

SCHEDULES

Filing Requirements Schedules Pages 1-12	NH PUC 1604-06 Filing Requirement Schedules
Schedule CGDN-1	2021 Rate Plan Outline
Schedule CGDN-2	Illustrative Revenue Requirement – 2021 Rate Plan
Schedule CGDN-3	Computation of Revenue Requirement for Temporary Rates

WORKPAPERS

Revenue Requirement Workpapers	Workpapers Supporting Revenue Requirement Schedules

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Christopher J. Goulding, and my business address is 6 Liberty Lane West, Hampton, New Hampshire 03842.

My name is Daniel T. Nawazelski, and my business address is the same as Mr. Goulding's.

Q. Mr. Goulding, what is your position and what are your responsibilities?

A. I am the Director of Rates and Revenue Requirements for Unitil Service Corp. ("Unitil Service"), a subsidiary of Unitil Corporation ("Unitil Corp" that provides managerial, financial, regulatory and engineering services to Unitil Corp's utility subsidiaries including Unitil Energy Systems, Inc. ("UES" or the "Company"). My responsibilities include all rate and regulatory filings related to the financial requirements of UES and Unitil Corp's other subsidiaries.

Q. Please describe your business and educational background.

A. In 2000 I was hired by NSTAR Electric & Gas Company ("NSTAR," now Eversource Energy) and held various positions with increasing responsibilities in Accounting, Corporate Finance and Regulatory. I was hired by Unitil Service in early 2019 to perform my current job responsibilities. I earned a Bachelor of Science degree in Business Administration from Northeastern University in 2000 and a Master's in Business Administration from Boston College in 2009.

Q. Have you previously testified before this Commission or other regulatory agencies?

A. Yes, I have testified before the New Hampshire Public Utilities Commission (the "Commission") on various financial, ratemaking and utility regulation matters, including utility cost of service and revenue requirements analysis. I have also testified before the Maine Public Utilities Commission and Massachusetts Department of Public Utilities on similar matters on several occasions.

Q. Mr. Nawazelski, what is your position and what are your responsibilities?

A. I am the Lead Financial Analyst for Unitil Service. In this capacity I am responsible for the preparation and presentation of distribution rate cases and in support of other various regulatory proceedings.

Q. Please describe your business and educational background.

A. I began working for Unitil Service in June of 2012 as an Associate Financial Analyst. Since then I have been promoted four times, the most recent promotion was to the role of Lead Financial Analyst in 2018. I earned a Bachelor of Science degree in Business with a concentration in Finance and Operations Management from the University of Massachusetts, Amherst in May of 2012.

Q. Have you previously testified before this Commission or other regulatory agencies?

A. Yes, I have testified before the Commission on various financial, ratemaking and utility regulation matters. I have also testified before the Maine Public Utilities

Commission and Massachusetts Department of Public Utilities on similar matters on several occasions.

II. SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to present and support UES in its request for a permanent increase in distribution base rates based on 2020 test year revenues and expenses and year-end rate base with pro forma adjustments for known and measurable changes consistent with Commission precedent. Also, as introduced in the prefiled testimony of Company witness, Mr. Robert Hevert, we describe the process and mechanics of the Company's requested multi-year rate plan (the "2021 Rate Plan"). Next, we describe and support the Company's request for a temporary increase in distribution base rates which would be subject to reconciliation based on the difference between permanent and temporary rates. Next, we discuss the Company's other regulatory proposals regarding waived late payment charges, deferred storm costs, wheeling revenues and Active Hardship Protected Accounts ("AHPA") and the impact of a customer's upcoming master meter plan. Next we explain the transition to decoupling from the current lost revenue recovery mechanism. We then describe proposed changes to the Company's External Delivery Charge ("EDC") tariff. Finally, we provide estimated rate case costs and proposed recovery of those costs.

Q. Please summarize the Company's conclusions with respect to its revenue requirement.

A. Based on test year results, as adjusted for known and measurable changes, for the twelve months ended December 31, 2020, the Company has determined the need to increase its base distribution revenues by $11,992,392 or approximately 4.4 percent over the Company's total revenue under present rates after accounting for changes to other reconciling mechanisms. These changes roll certain items, such as lost base revenue, regulatory assessments and vegetation management expense, currently collected through reconciling mechanisms reimbursement into base distribution rates. The request is founded on the need for achieving, after payment of all operating expenses, taxes and other charges, a weighted average cost of capital of 7.88 percent that includes a return of equity ("ROE") of 10.00 percent.

Q. Please elaborate on the changes in existing reconciling mechanisms described above.

A. The Company currently collects certain costs including lost base revenue, regulatory assessments and vegetation management expenses through reconciling mechanisms. The proposed adjustments in the instant proceeding move the recovery of these costs through reconciling mechanism to base rates. While these adjustments reflect significant increases to base rates, it does not reflect any additional impact to ratepayers or additional revenue to the Company. Rather, it simply moves recovery of the costs from the reconciling mechanisms to base rates. Each of these proposed adjustments is described in greater detail below with the applicable reconciling mechanisms that are impacted. The movement of these costs results in the Company's net base revenue increase of $9,349,601 after adjusting for the cost recovery movement has been summarized in Table 1 below.

Table 1: Net Revenue Deficiency Increase

Description	Reference	Amount
Revenue Deficiency	Schedule RevReq-1, Line 7	$ 11,992,392
Cost Recovery Movement		
Lost Base Revenue	Per Company Calculation	$ (1,076,981)
Regulatory Assessments	Schedule RevReq-3-8, Line 5	$ (159,383)
VMP Expense	Schedule RevReq-3-3, Line 19	$ (1,406,427)
Net Revenue Deficiency		$ 9,349,601

III. DEVELOPMENT OF THE DISTRIBUTION REVENUE REQUIREMENT

A. METHOD OF ANALYSIS

Q. What approach did you use to perform the revenue requirement analysis?

A. To perform the revenue requirement analysis, we determined the cost of service, using a test-year approach as pro formed and adjusted for material, known and measurable changes. We then compared the cost of service to test year revenues (as adjusted) to derive a revenue deficiency, and the corresponding revenue requirement that UES would have to receive on a test year basis to make up this deficiency. The deficiency is then increased for state and federal income taxes to determine the revenue deficiency.

Q. What was the test year for computing the Company's cost of service?

A. The test year is the twelve-month period ending December 31, 2020, which is the most recent calendar year for which data is available. Calendar year 2020 data is also readily verifiable to the most recent annual reports submitted by UES.

Q. What standards were employed to determine the pro forma adjustments?

A. All adjustments to the test year cost of service are based upon known and measurable changes to revenues and expenses, or upon changes that will become known and measurable during the course of this proceeding. As a practical matter, the Company has limited all pro forma adjustments to those that will be known and measurable through April 1, 2022, which is the date permanent rates are expected to go into effect for this proceeding.

Q. Why are these standards important?

A. The rates established in this proceeding should provide UES with sufficient revenues to continue to ensure safe, reliable and cost-effective delivery service for UES's customers and to provide a reasonable opportunity for UES to earn its authorized rate of return. UES has a reasonable opportunity to earn its allowed rate of return when the proposed rates reflect, as closely as possible, the cost of service that UES will actually experience when permanent rates are awarded.

Q. Have you followed the Commission's required format for presenting the calculation of the proposed revenue requirement?

A. Yes, to the best of our knowledge. We have followed the requirements as described in New Hampshire Code of Administrative Rules, Chapter Puc 1600

Tariffs and Special Contracts, Part Puc 1604 Full Rate Case Filing Requirements, Sections Puc 1604.06 through 1604.09. The Filing Requirement Schedules specified in Sections Puc 1604.06 and 1604.07 have been provided as "Filing Requirement Schedules Pages 1-12." The Filing Requirement Schedules are a summary of the actual revenue requirement model which drives the underlying calculations of the revenue deficiency. This revenue requirement model will be referred to throughout the rest of our testimony as "RevReq" schedules. The Rate of Return Information specified in Section Puc 1604.08 has been provided in Schedules RevReq-5 through 5-7. The Adjustments to Test Year specified in Section Puc 1604.09 have been provided in Schedules RevReq-3 through 3-21.

Q. Has UES filed other material as required by Part Puc 1604 Full Rate Case Filing Requirements?

A. Yes. The material required by Section Puc 1604.01, Contents of a Full Rate Case, has been provided with this filing as separate volumes of materials.

B. SUMMARY OF RESULTS

Q. Please summarize the results of your revenue requirement analysis.

A. In the current proceeding, the Company is requesting rate adjustments related to the Base Distribution function. As shown on Schedule RevReq-1, comparing the adjusted cost of service to the adjusted operating revenues derives the Base Distribution revenue deficiency for the test year of $11,992,392 based on an overall rate of return on rate base of 7.88 percent and known and measurable adjustments to test year revenues, expenses, and rate base.

Q. Please describe the test year operating income, as adjusted, and used to determine the revenue deficiency.

A. The revenue requirement schedules and workpapers for UES in the test year are presented in Schedule RevReq-1 through RevReq-6 and Workpapers supporting the revenue requirement schedules. The pro forma operating income for UES in the test year is presented in Schedule RevReq-2 pages 1 and 2. On page 1, the "per books" revenues, operating expenses and net operating income are set forth in column (2), labeled "Test Year 12 Months Ended 12/31/20." In Column (3), labeled "Test Year Flow-Through," test year revenue and operating expenses associated with various non-base rate mechanisms are summarized. The rate mechanism results in column (3) are subtracted from column (2) to arrive at "Test Year Distribution" results in column (4). The proposed normalizing adjustments are set forth in the column (5), labeled "Proforma Adjustments." The adjusted revenues, operating expenses and net operating income are set forth in column (6), labeled, "Test Year Distribution as Proformed." The final two columns contain operating revenues and expenses for the two preceding calendar years 2019 and 2018. On page 2 of Schedule RevReq-2, the proposed normalizing adjustments are set forth in column (3), labeled "Pro Forma Adjustments." The pro forma adjustments are added to column (2), labeled "Test Year Distribution," to obtain the adjusted revenues and operating expenses in column (4), labeled

"Test Year Distribution as Pro Formed." The pro forma operating income from column (4) is used to determine the operating income deficiency which is summarized in Schedule RevReq-1. The pro forma operating income from column (4) is used to determine the operating income deficiency which is summarized in Schedule RevReq-1. Schedule RevReq-1 calculates the income required by multiplying rate base by the rate of return. The pro forma operating income from column (4) Schedule RevReq-2, pages 2 of 2 is then subtracted from the income required in Schedule RevReq-1 to obtain the operating income deficiency. This operating income deficiency is then grossed up for federal and state taxes to obtain the revenue deficiency as shown in Line 7 of Schedule RevReq-1.

Q. Please describe the pro forma adjustments that are shown in column (5) of Schedule RevReq-2.

A. As shown, we have made pro forma adjustments to the following areas:

- Revenue
- Operating and Maintenance Expenses
- Depreciation and Amortization
- Taxes Other than Income
- Federal and State Income Taxes
- Net Book Value, Accumulated Deferred Taxes & Excess Deferred Taxes (Rate Base)

These pro forma adjustments are detailed on Schedule RevReq-3 and on subsequent schedules as identified.

Q. Have you provided additional schedules that summarize the results of your revenue requirements analysis and support the rate change requested?

A. Yes, we have. Schedule RevReq-4 contains all rate base components, including plant in service, accumulated depreciation, and deferred income taxes, as well as associated rate base related pro forma adjustments. Lastly, Schedule RevReq-5 provides the calculations showing the Company's requested return on rate base of 7.88 percent.

C. DISTRIBUTION REVENUE REQUIREMENT

I. TOTAL OPERATING REVENUES

Q. What adjustments were made to Total Operating Revenues?

A. We made the following adjustments to total operating revenues:

- Non-Distribution Bad Debt
- Unbilled Revenues
- New Distribution Operating Center ("DOC") Rent Revenue
- Late Fees

1. NON-DISTRIBUTION BAD DEBT

Q. Please explain the non-distribution bad debt adjustment.

A. Total revenues have been decreased by $143,623 to remove accrued revenue associated with non-distribution bad debt. A similar adjustment was made to decrease operating expenses by $143,623 which is the provision for non-distribution bad debt in operating expenses. These adjustments are summarized in Schedule RevReq-3-1. Overall, there is no impact on the revenue requirement since both the revenue and operating expenses are adjusted by the same amount.

2. UNBILLED REVENUE

Q. Please explain the unbilled revenue adjustment.

A. The Company books unbilled revenue to account for the difference between the amount of electricity delivered to customers during the test year and the amount billed to customers during the same period. The accrual for the amount of unbilled sales was removed from the test year. This adjustment decreases revenue by $137,189 as shown in Schedule RevReq-3-1.

3. NEW DOC REVENUE

Q. Please explain the new DOC rent revenue adjustment.

A. The Company has increased test year revenue by $313,007 for estimated rent revenue received from Unitil Service for use of the new Exeter DOC. The Company intends to update this amount for actual 2021 rent revenues during the pendency of this case, but does not expect the amount to materially change from its estimate.

4. LATE FEE REVENUE

Q. Please explain the late fee revenue adjustment.

A. The Company has increased test year revenue by $180,938 to normalize the late payment charge revenue to the 2019 level to account for the Governor and Commission order issued in March 2020 that prohibited the charging of customers late payment fee. The moratorium resulted in the Company collecting a non-representative level of late payment charge revenue in the test year.

Q. Is the Company proposing to recover the lost late payment charge revenues associated with the moratorium that is currently in place?

A. Yes, the details of the proposal are explained below in Section VI "Other Regulatory Proposals and Considerations".

II. OPERATING & MAINTENANCE EXPENSES

Q. What is the amount of UES's per books Operating & Maintenance Expense?

A. In the test year, UES incurred $22,748,486 of Operating & Maintenance ("O&M") Expense related to Distribution, as shown on Schedule RevReq-2, Page 2, Column 2, Line 7 through 12.

Q. What adjustments were made to O&M Expenses?

A. Pro forma adjustments are included in the distribution cost of service for the following O&M Expenses:

- Non-Distribution Bad Debt
- Payroll
- Vegetation Management Expense ("VMP")
- Medical & Dental Insurances

- Pension, Postemployment Benefits Other than Pension, Supplemental Executive Retirement Plan, 401K, and Deferred Compensation Plan Expense
- Property & Liability Insurance
- DOC Expense
- Commission Regulatory Assessment
- Dues and Subscriptions
- Pandemic Costs
- Claims & Litigation
- Severance
- Distribution Bad Debt
- Protected Receivables
- Arrearage Management Program ("AMP") Implementation Cost
- Inflation Allowance

We will discuss each adjustment individually in the following section.

1. NON-DISTRIBUTION BAD DEBT

Q. Please explain the adjustment for Non-Distribution Bad Debt

A. As discussed earlier in our testimony, we removed revenue associated with non-distribution bad debt. In O&M Expense, we also remove these same amounts on Schedule RevReq-3-1.

2. PAYROLL

Q. What adjustment was made to payroll?

A. The payroll adjustment, as reflected on Schedule RevReq-3-2 Page 1, adjusts the test year payroll charged to O&M Expense for the following:

1. Annualization of the pay rate increases that have occurred during calendar year 2020 for the union employees;
2. The effect of pay rate increases that occurred on January 1, 2021 and will occur on June 1, 2021 and that are projected to occur on January 1, 2022 and June 1, 2022.

These adjustments have been made to the payroll for both UES and Unitil Service. The 2022 wage increases are estimated for the purposes of this initial filing, but will be updated with actual results before the completion of this proceeding. Test year incentive compensation was booked to the target level so no adjustment is required. The pro forma increase to test year O&M payroll is $709,516 as shown on Schedule RevReq-3-2 Page 1, Column 6, Line 13. This adjustment is discussed in more detail in the prefiled testimony of Mr. John Closson and Mr. Joseph Conneely.

3. VEGETATION MANAGEMENT & RELIABILITY ENHANCEMENT PROGRAM

Q. What is the purpose of the Vegetation Management Program ("VMP") and Reliability Enhancement Program ("REP") adjustment?

A. The VMP and REP expense has been pro formed to increase the test year expense by $1,406,427 to adjust the total VMP and REP expense recovery through base distribution rates to $6,265,166. This amount equals the revised amount of program costs that the Company filed for in the 2021 VMP in DE 20-183. The increase of $1,406,427 is due to an increase of $416,927 in the 2021 budgeted amount above the test year 2020 amount of $5,848,239 and the removal of the $989,500 credit associated with the reimbursement from third party vendors who reimburse the Company for a portion of the vegetation management that the Company performs. While the adjustment is significant, it does not reflect any additional impact to ratepayers or additional revenue to the Company. Rather, it merely moves recovery of the full costs of vegetation program from the EDC mechanism to base rates.

Q. What is the Company proposing related to potential future reimbursements from third party vendors?

A. The Company is proposing that any reimbursement received will be returned to customers via the EDC. This is consistent with the current treatment of the reimbursement.

Q. Is the Company proposing to continue annually reconciling the actual REP and VMP expenses through the EDC?

A. Yes, consistent with the current process, the Company is proposing to continue to reconcile annually the actual VMP and REP expense to the amount included for recovery in base distribution rates and refund or recover the difference as part of the EDC. The only difference from the current process and this proposal is that the Company is proposing to update the amount of recovery in base distribution rates in order to reduce the amount of VMP and REP cost recovered via the EDC.

4. MEDICAL & DENTAL INSURANCE

Q. What is the purpose of the Medical & Dental Insurance Adjustment?

A. The test year O&M expense has been pro formed to increase test year medical and dental insurance by $359,921. This adjustment is shown on Schedule RevReq-3-4, and includes amounts allocable to UES from Unitil Service. The adjustment is based on actual working rates for 2021, and an estimated increase for 2022. Before the completion of this proceeding, this adjustment will be updated to reflect actual 2022 working rates. This adjustment is supported and presented in the prefiled testimony of Mr. John Closson and Mr. Joseph Conneely.

5. RETIREMENT COSTS

Q. Please explain the pension, postemployment benefits other than pension, supplemental executive retirement plan, 401(k) adjustments and deferred compensation expense.

A. The purpose of the pension, postemployment benefits other than pension (PBOP), supplemental executive retirement plan (SERP), 401(k), and deferred compensation expense adjustments is to update these costs from test period O&M expense. The latest year-end 2020 actuarial report, which provides 2021 calendar year expense, was the basis for the pension, PBOP, and SERP adjustment. The 2020 401(k) and deferred compensation expense was adjusted to reflect the effect of the payroll increases referenced above. The pension, PBOP, SERP, 401 (k), and deferred compensation expense adjustments are all provided in Schedule RevReq-3-10 which shows a pension increase of $62,288, a decrease to PBOP expense of $41,636 and increases to SERP, 401(k) and deferred compensation expense of $85,989, $41,844 and 64,957, respectively. These adjustments include costs for the Company as well as costs allocable to the Company from Unitil Service. This adjustment is supported and presented in the prefiled testimony of Mr. John Closson and Mr. Joseph Conneely.

6. PROPERTY & LIABILITY INSURANCE

Q. Please describe UES's property and liability insurance coverage and the adjustment to test year property and liability insurance expense.

A. Property and liability insurance coverage includes a number of types of insurance that provide protection from casualty and loss, and other damages that the Company may incur in the conduct of its business. UES's insurance program includes both premium-based and self-insured coverages, in order to obtain the widest portfolio of insurance coverage at the most reasonable cost. As shown on Schedule RevReq-3-6, the pro forma adjustment for property and liability insurances is an increase of $72,468 to test year O&M expense. This adjustment was made to adjust the property and liability insurance test year O&M expense to reflect known and measurable changes in premiums for the Company and for premiums allocable to the Company from Unitil Service. The premiums shown on Schedule RevReq Workpaper 5.3 include actual costs for 2021 insurance policies. The Company will provided actual costs for 2022 insurance policies when they become available during the course of this proceeding.

Q. Please describe how the Company takes reasonable measures to control property and liability insurance.

A. The Company evaluates its property and liability annually with the aid of its insurance broker to ensure the Company is able to secure the best available coverage at the best available rates. To balance the risk mitigation that insurance provides and the level of premium costs, an appropriate level of self-insurance deductible is negotiated with insurance carriers. Higher deductible levels result in lower insurance premiums while also resulting in a higher retention of risk of loss. The Company must manage the balance between risk exposure and deductible cost.

The Company employs a well-accepted process when procuring insurance programs. To get the optimal coverage at the best cost, the Company uses its broker to facilitate the process. The broker compiles market submissions and works with various insurance markets to solicit quotes for the Company. The broker monitors the insurance markets and provides information helpful to coordinate a reasonable renewal. The Company's broker also benchmarks our peers to see how our limits and retentions compare in the industry. If adjustments are needed, the benchmarking analysis provides support to senior management to support any changes. On a combined basis, these processes assist in assuring that the Company's property and liability insurance are as reasonable as possible.

7. DISTRIBUTION OPERATION CENTER EXPENSE

Q. Please explain the adjustment related to DOC expense.

A. This adjustment adds in estimated O&M expense at the Company's new Exeter DOC and removes the amount of expense in the test year related to the Company's Kensington DOC. The result is a reduction of DOC operating expense of $1,968 as shown in Schedule RevReq-3-7. These expenses relate to items such as heating, cooling, snow removal, and other miscellaneous administration and general expense. The Company will update the estimated Exeter DOC expense to 2021 actuals during the pendency of the case.

8. REGULATORY ASSESSMENT FEES

Q. Please explain the adjustment related to regulatory assessment fees.

A. Currently, the Company collects regulatory assessment fees in base rates, through its EDC mechanism and $10,000 through default service rates. The proposed adjustment shown in Schedule RevReq-3-8 moves all recovery, except for $10,000 recovered as part of default services rates, into base rates, with any incremental changes continuing to be recovered or refunded through the EDC mechanism. The adjustment increases expenses by $159,383 and is necessary to comply with the requirements in RSA 363-A:6,I. The adjustment does not reflect any additional impact to ratepayers or additional revenue to the Company. Rather, it merely moves recovery of the assessment from the EDC mechanism to base rates.

9. DUES & SUBSCRIPTIONS

Q. Please explain the adjustment related to dues and subscriptions.

A. The Company has reduced test year operating expense by $14,473 in Schedule RevReq-3-9 to remove the lobbying portion of the Company's annual membership dues to the Edison Electric Institute to comply with the requirements in RSA 378:30-e.

10. PANDEMIC COSTS

Q. Please explain the adjustment related to pandemic costs.

A. As shown in Schedule RevReq-3-10, this adjustment removes $39,857 of pandemic related costs that were charged during the 2020 test year. On a forward looking basis the Company believes that these costs were anomalous and should not be included for ratemaking purposes.

11. CLAIMS & LITIGATION

Q. Please explain the adjustment related to claims and litigation.

A. In December of 2019 the Company inadvertently charged $44,072 of expense to UES instead of its other affiliate Northern Utilities – Maine Division. A reclassification entry was made in January of 2020 to move the expense from UES to Northern Utilities – Maine Division. Test year operating expenses have been increased by $44,072 to remove the impact associated with this entry during the test year as shown on Schedule RevReq-3-11.

12. SEVERANCE EXPENSE

Q. Please explain the adjustment related to severance expense.

A. As reflected in Schedule RevReq-3-12, we have reduced test year severance expense by $40,395. The Company believes that severance expense is a periodically recurring expense but that the test year expense may not be a representative level. Therefore, the Company normalized test year expense to reflect a representative test year level to be recovered in rates, calculated as the average of the most recent five-year expense amounts.

13. DISTRIBUTION BAD DEBT

Q. Please explain the adjustment of test year distribution bad debt expense.

A. The calculation of this adjustment is shown in Schedule RevReq-3-13. This adjustment was developed by first calculating a bad debt rate based on 2019 delivery net write-offs divided by 2019 delivery billed revenue. We then multiplied the bad debt rate by test year delivery revenue including the revenue requirement from Schedule RevReq-1, which establishes an uncollectible revenues amount. The uncollectible revenues amount is compared to test year delivery write-offs to produce the pro forma adjustment of $134,563.

Q. Why did the Company choose to use 2019 delivery net write-offs and 2019 delivery billed revenue?

A. The Company is proposing to use the 2019 delivery net write off percent due to the disconnection moratorium that was issued beginning in March 2020 by the State of New Hampshire and ordered in Docket No. IR 20-089 because the level of write off activity in 2020 was not reflective of a normal year's level.

Q. How is the Company proposing to address the write off activity that will occur once the disconnection moratorium is lifted?

A. To ensure that the Company is recovering a representative level of bad debt expense in distribution rates, the Company is proposing to track the actual delivery write offs against the level in distribution rates and to recover the difference annually as part of the EDC. Due to the shut off moratorium, the Company does not expect actual write-offs to return to pre-pandemic levels for some time.

Q. Has the Commission issued an order allowing New Hampshire Utilities to recover incremental bad debt expense?

A. No, an order has not been issued but Docket IR No. 20-089 was opened to investigate the effects of the Covid-19 Emergency on utilities and customers. In this investigation the New Hampshire Public Utilities Commission Staff ("Staff") issued an Initial Recommendation on August 18, 2020 and a Revised Recommendation on November 13, 2020 that the utilities be allowed to recover incremental bad debt expense above the amount recovered in rates. The Staff's Initial Recommendation stated:

> The pandemic is an unprecedented and extraordinary event. However, because the pandemic is on-going with no certainty as to when it may end, it is not possible to reasonably assess the long-term financial impact the pandemic will have on the Utilities and their customers. Consequently, while the pandemic may be an extraordinary event, there is insufficient evidence at this time to determine what, if any, extraordinary treatment is warranted beyond that related to the severe impact the pandemic is expected to have on utility bad debt expense and lost revenue from waived fees.
>
> Given the Governor's and Commission's orders prohibiting utility disconnections, it is appropriate and reasonable to authorize the Utilities to use regulatory accounting for impacts associated with the prohibition on

> utility disconnections, waiver or exclusion of certain utility fees (i.e., late fees, convenience fees, deposits, and reconnection fees), and the use of expanded payment arrangements to aid customers, and resulting impacts on uncollectible, or bad debt, expenses. The waived fees and incremental bad debt (amounts in excess of the amounts used to set current rates) should be accounted for beginning March 31, 2020 (the date of the Commission Order).

IR 20-089, Staff Recommendation at 5 (Aug. 18, 2020)

Q. How is the Company proposing to recover the incremental bad debt expense that the Company has incurred beginning March 31, 2020?

A. Consistent with the bad debt tracker proposal above, the Company is proposing to track the actual bad debt expense to the amount currently in distribution rates and to recover or flow back the incremental difference through the EDC.

14. ARREARAGE MANAGEMENT PROGRAM IMPLEMENTATION

Q. Please explain the adjustment for Arrearage Management Program ("AMP") implementation.

A. The Company is proposing an AMP as part of the filing as provided in the prefiled testimony of Carole Beaulieu. The $459,000 amount shown on Schedule RevReq-3-14 is related to the estimated cost of a full time employee to be hired to run the program, and the annual program forgiveness costs.

Q. What happens if the program cost are greater or less than the $459,000 include for recovery in base distribution rates?

A. The Company is proposing to track the actual cost of the program and reconcile the cost annually against the $459,000 that is included in base distribution rates.

Any variance from the level in rates will be deferred and refunded or recovered as part of the following years EDC.

15. INFLATION ALLOWANCE

Q. Is the Company proposing an Inflation Allowance?

A. Yes, it is. We have calculated an inflation allowance to recognize the impact of inflation over time on the Company's expenses. The inflation adjustment recognizes that known inflationary pressures, not subject to the control of UES, tend to affect the Company's operating expenses in a manner that can be reasonably measured. The adjustment is limited to an allowance for those expenses that cannot be adjusted separately ("residual O&M Expense") and extends to the date that permanent rates go into effect.

Q. Please describe the adjustment for Inflation.

A. An inflation allowance has been applied to test year residual O&M Expenses, as shown on Schedule RevReq-3-15 Page 1. In order to determine the level of test year residual O&M Expenses, we reduced test year O&M Expenses by: (1) expenses that have been adjusted separately; and (2) expenses that are not subject to general inflation. The inflation adjustment on residual O&M is based on a cumulative inflation rate of 3.36 percent over a 21-month period, which represents the increase in the Gross Domestic Product Implicit Price Deflator ("GDPIPD") from the mid-point of the test year (July 1, 2020) to April 1, 2022 (date of permanent rates), as shown on Schedule RevReq-3-15 Page 2. We have also provided the published GDPIPD factors on a monthly basis from 2019 to the currently available end of year 2022 in Workpaper 6.1.

Q. What inflation allowance was calculated?

A. The calculation produces an inflation allowance of $128,368 as shown on Schedule RevReq-3-15 page 1, line 20.

III. DEPRECIATION EXPENSE

Q. Is UES proposing an annualization adjustment for depreciation for the test year?

A. Yes. We have applied the currently authorized depreciation rates to test year-end depreciable plant balances to derive the annualized Depreciation Expense. The annualization of depreciation expense based on the twelve months ended December 31, 2020 depreciable plant balance is detailed in Schedule RevReq-3-16 page 1. The annualization adjustment increases the depreciation expense by $908,712. This adjustment also reflects the pro forma rate base adjustments related to the Kensington and Exeter DOC's, which we will describe in further detail below.

Q. What depreciation rates did you use for the annualization adjustment?

A. The Company used the depreciation rates that were approved in the Company's last settlement agreement in Docket No. DE 16-384.

Q. Is the Company proposing an adjustment to depreciation expense for any proposed changes in depreciation rates?

A. Yes. The depreciation adjustment, detailed on Schedule RevReq-3-16 page 2, decreases the test year depreciation expense by $789,749. The new depreciation rates and reserve adjustment for amortization are presented in the prefiled testimony of Mr. Ned Allis.

IV. AMORTIZATION EXPENSE

Q. Have you made any adjustments to amortization expense for information technology or software projects?

A. Yes. We have made an adjustment to provide for an adequate level in the cost of service for information technology and software amortization expense based upon known and measurable changes through the end of 2021.

Q. Please describe the methodology you used for this adjustment.

A. As provided in Schedule RevReq-3-17, the Company projected rate year amortization based on projects currently in service and expected information technology projects to be put in service through the end of 2021. Then, the adjustment removes the amortization expense of any project expected to be fully amortized during 2021. The Company then compares the projected rate year amortization versus the test year for an increase of $238,591. The Company will update this adjustment during the course of the proceeding for actual information technology projects to be put in service through the end of 2021.

V. EXCESS ACCUMULATED DEFERRED INCOME TAXES ("ADIT")

Q. Please explain the Excess ADIT adjustment.

A. As described further in the Testimony of Jonathan A. Giegerich, the Company is proposing to begin flowing back Excess ADIT to ratepayers. The Excess ADIT flowback included in the revenue requirement calculation is $999,795, as shown in ScheduleRevReq-3-18. The detailed calculation of the Excess ADIT flowback has been included as Exhibit JAG-6, Page 1 of 1, column d, line 4.

VI. TAXES OTHER THAN INCOME

1.PROPERTY TAXES

Q. Has the Company adjusted the test year property tax expense?

A. Yes. The adjustment is detailed on Schedule RevReq-3-19 and amounts to an estimated increase in property tax expense of $744,985. This schedule presents information related to property taxes including taxation period, local tax rate, assessed valuations, and taxes paid based on final 2020 tax bills by municipality. The adjustment also includes pro forma adjustments to increase property taxes for the new Exeter DOC as well as the removal of property taxes related to the Kensington DOC.

Q. Will this adjustment be updated?

A. Yes. This adjustment will be updated during the pendency of this proceeding to reflect the final 2021 tax bills. Typically, the second billing installments are received in October and November, with payments due in November and December.

Q. Were there property tax abatements received during the test year?

A. Yes, the test year reflects on line 39 of Schedule RevReq-3-19 an amount of $38,265 related to property tax abatements received in 2020 for prior years, which do not impact the Company's current year's taxes and thus need to be removed.

Q. Have any other adjustments been made to test year property taxes?

A. Yes. Test year property taxes on line 38 of Schedule RevReq-3-19 have been reduced by $12,231 to remove an inadvertent accrual adjustment entry related to 2019.

Q. How is the Company planning to address the future changes in property taxes that will occur related to HB 700?

A. As described in greater detail below is Section IV, the Company is proposing to track and recover the increase in local property taxes as part of the EDC.

2. PAYROLL TAXES

Q. Have test year payroll taxes been adjusted to account for pro forma payroll increases?

A. Yes, as shown on Schedule RevReq-3-20 P1, an adjustment of $54,278 was prepared to pro form the amount of UES's and Unitil Service's portion of the Social Security and Medicare taxes related to the adjustment to the payroll adjustment described above. The adjustment is supported and presented in the prefiled testimony of Mr. John Closson and Mr. Joseph Conneely.

Q. Have test year payroll taxes been adjusted for employee retention and other pandemic payroll tax relief credits?

A. Yes, as shown on Schedule RevReq-3-20 P2, an adjustment of $106,244 was prepared to remove the reduction to test year payroll taxes as a result of the Company's use of employee retention and other pandemic payroll tax relief credits. The adjustment is supported and presented in the prefiled testimony of Mr. Jonathan Giegerich.

VII. INCOME TAXES

Q. Does the cost of service reflect adjustments to test year income taxes to reflect pro forma changes?

A. Yes. The adjustment is summarized on Schedule RevReq-3-21, pages 1-2. The adjustment to test year income taxes calculates the income tax effect of the adjustments to expenses previously described in our testimony and as listed in the Summary of Adjustments in Schedule RevReq-3. The adjustment also reflects the income tax effect of the adjustment for interest expense synchronization with rate base, based on the difference between interest expense for ratemaking and test year interest expense, which is shown on Schedule RevReq-3-21, page 2.

Q. Please explain the adjustments for prior year federal and state income taxes as shown in Schedule RevReq-3-21, page 4.

A. As part of its normal tax accounting practice, the Company accounts for prior years return to accrual in its current year tax provision. The adjustment in Schedule RevReq-3-21 page 4 removes the prior year return to accrual and other prior year tax adjustments so that the adjusted cost of service reflects current year income taxes only.

VIII. RATE BASE

Q. Have you provided the balance sheets for UES?

A. Yes, we have provided Assets & Deferred Charges and Stockholder's Equity and Liabilities in Filing Requirements Schedule 2 and 2a, Page 6 & 7, respectively.

Q. Please summarize the information you have provided to support the rate base used to determine UES's revenue requirements.

A. Schedule RevReq-4 summarizes the rate base. The summary includes several calculation methodologies, including the "Test Year Average" (arithmetic average of the beginning and end of test period amounts) of $206.5 million, the "5 Quarter Average" of $197.8 million, the "Rate Base at December 31, 2020" of $223.5 million, and the "Pro Forma Rate Base at December 31, 2020" of $226.0 million. The pro forma rate base at December 31, 2020, was used to determine UES's revenue requirement.

Q. What did you consider in selecting a year-end rate base?

A. Utility Plant in Service consistently increases quarter-over-quarter. Thus, a year-end rate base is appropriate for UES given the significant annual growth in the primary component of its rate base, Utility Plant. As described in greater detail in the prefiled testimony of Mr. Robert Hevert, UES is a capital intensive Company, and without the timely recovery on those investments revenue will not be sufficient to cover incremental costs, which leads to earnings attrition. A year-end rate base reduces earnings attrition, because it aligns expenses, revenues and rate base with the period in which rates are going to be in effect. Finally, the year-end rate base was utilized in the Company's last two base distribution rate cases in Docket DE 10-055 and Docket DE 16-384, and we believe it is appropriate to continue this practice.

Q. Since the Company's last base rate proceeding, has UES added utility plant to its operations?

A. Yes. Pro Forma Distribution Utility Plant in Service has grown from $283,122,968 in pro forma 2015 (the Company's most recent rate case test year) to $407,914,123 in pro forma 2020 (a 44.1 percent increase). Adjusting these amounts by the 2015 and 2020 Reserves for Depreciation and Amortization, Net Utility Plant has grown from $184,142,932 in pro forma 2015 to $269,855,036 in pro forma 2020 (a 46.5 percent increase). Refer to Docket No. 16-384 Settlement Agreement, Attachment 1, Page 1 of 5 for pro forma 2015 information and Schedule RevReq-4, column 7 for pro forma 2020 information.

Q. Please describe the component of rate base information on Schedule RevReq-4-1.

A. Schedule RevReq-4-1 presents the balance of rate base items for each of the 5 quarters beginning with the balance at December 31, 2019 and ending with the balance at December 31, 2020. In the last column, the 5-Quarter Average is calculated.

Q. Please describe the cash working capital component of rate base information on Schedule RevReq-4-2.

A. The calculation of cash working capital in rate base is detailed in this schedule. The calculation consists of a 32.17 day lead-lag factor applied to test year distribution operating expenses. This lead-lag factor is based on the Company's lead-lag study as presented in the prefiled testimony of Mr. Daniel Hurstak. UES proposes to include $3,350,303 of cash working capital in Base Distribution rate base.

Q. What is cash working capital?

A. As described in greater detail in the prefiled testimony of Mr. Daniel Hurstak, cash working capital is the amount of capital expended and required by UES to fund its day-to-day operations. In other words, cash working capital represents funds expended by the Company to provide service prior to the payment for such service by UES's customers. Pursuant to Commission precedent, cash working capital is an addition to UES's rate base.

Q. Please list the other components added to rate base.

A. In addition to Net Utility Plant in Service and Cash Working Capital described above, Materials and Supplies Inventories, Prepayments and Deferred Tax Debits, have all been added to rate base. These items are shown on Schedule RevReq-4 and RevReq 4-1.

Q. Please list the components deducted from rate base.

A. These items consist of Net Deferred Income Taxes, Excess Deferred Income Taxes, Customer Deposits, and Customer Advances and are also shown on Schedule RevReq-4 and 4-1.

Q. Has the Company revalued all ADIT as of December 31, 2017 to reflect a 21 percent federal tax rate as a part of Tax Cuts and Jobs Act of 2017 ("TCJA")?

A. Yes. As discussed further in the prefiled testimony of Mr. Jonathan Giegerich, the most significant corporate effect of the TCJA is reducing the top federal corporate tax rate from 35 percent to 21 percent, which caused the Company to revalue all ADIT balances as of December 31, 2017. The corresponding entry to reduce net ADIT Liabilities was recorded as a Regulatory Liability according to Federal Energy Regulatory Commission ("FERC") guidance, Docket No. AI93-5-000. According to FERC guidance, once a utility's ADIT are no longer owed to the government under the new rates, and the ADIT balance represents amounts previously collected from customers in utility rates, the Liability for excess ADIT no longer exists and, instead, a Regulatory Liability for the amounts to be returned to customers exists and will be properly classified that way in the FERC chart of accounts, Docket No. AI93-5-000.

Q. Please describe how the Company calculated excess ADIT as of December 31, 2017.

A. The Company scheduled out into future periods the timing of the turning of its ADIT balances and reconciled all of its ADIT underlying book/tax temporary differences as of December 31, 2017. Once the underlying book/tax temporary differences were reconciled, the Company adjusted, or "revalued," the federal ADIT accounts at the new federal corporate tax rate. A net Regulatory Liability in the amount of $16,601,346 was recognized to be returned to customers in future rates and is shown in Schedule RevReq-4 and Schedule RevReq-4-1. As described later in our testimony, the Company has included an adjustment that reduces the December 31, 2020 net Excess ADIT balance by $1,928,356. This results in a pro forma Excess ADIT balance as of $14,672,991 as shown on Schedule RevReq-4, Column 7, Line 9.

Q. Please explain Schedule RevReq-4-3, which contains an adjustment to Utility Plant in Service and Net Deferred Income Taxes related to the Company's Kensington, NH DOC.

A. The Company has included a reduction to Utility Plant in Service of $988,214, as shown on Schedule RevReq-4-3, Column 2, Line 4, to account for the Company's DOC in Kensington, New Hampshire. As discussed in greater detail in the prefiled testimony of Mr. John Closson, the process to sell the Kensington facility and property is underway, thus the net book value associated with the building should be excluded from the Company's rate base for ratemaking purposes. The rate base reduction is offset by the appropriate amount of deferred taxes as shown on Schedule RevReq-4-3, Column 2, Line 6.

Q. Please explain Schedule RevReq-4-4, which contains an adjustment to Utility Plant in Service related to the Company's new DOC in Exeter, NH.

A. The Company has included an increase to Utility Plant in Service of $577,144, as shown on Schedule RevReq-4-4, Column 2, Line 5, to account for the carry-over work closed to Plant in Service during the two months ended February 28, 2021 related to the new Exeter DOC. As discussed later in our testimony, the Company has excluded the forecasted 2021 capital additions from the proposed 2021 Rate Plan. The Company intends to exclude the additions placed into service during the first two months of 2021 related to the new Exeter DOC in its first step adjustment for recovery of additions placed into service during investment year 2021.

Q. Please explain Schedule RevReq-4-5, which contains an adjustment to Excess ADIT.

A. The Company has included a reduction to the Excess ADIT of $1,928,356 on Schedule RevReq-4-4, Column 2, Line 6. As of December 31, 2020 the Company's Major Storm Cost Reserve ("MSCR") had an under-collected balance of $3,275,423. This balance has been relatively constant since the Company's last rate case in DE 16-384. The Company is proposing to flow back the annual Excess ADIT for calendar years 2018-2020 of $2,644,590 to reduce the year-end 2020 MSCR under-recovered balance to $630,833. This allows the Company to significantly reduce the MSCR under-collected balance without increasing rates for customers. The Excess ADIT reduction is offset by the appropriate amount of deferred taxes for a net reduction to Excess ADIT of $1,928,356.

Q. Is the Company proposing to adjust the current level of MSCR Funding in rates?

A. Not at this time. Based on the review of the last 5 years of storm cost, not including the costs for storm that were recovered as part of the Storm Recovery Adjustment Factor ("SRAF"), the Company has determined that current annual recovery amount of $800,000 is a representative level.

IX. RATE OF RETURN

Q. What rate of return have you used for ratemaking purposes?

A. As shown on Schedule RevReq-5, UES's weighted cost of capital is calculated to be 7.88 percent. As described in the prefiled testimony of Mr. Todd Diggins, this is derived from the Company's capital structure and related costs for various capital components and represents the required rate of return on rate base used in the determination of the Company's revenue requirement.

Q. Please summarize the total rate of return.

A. The Company's weighted cost of capital is 7.88 percent, as shown on Schedule RevReq-5. We have applied this weighted cost of capital to the rate base of $226,030,082, shown on Schedule RevReq-1, to calculate the return on the rate base. The result is a total required return on rate base of $17,811,170 as shown on Schedule RevReq-1, line 3.

IV. 2021 RATE PLAN

Q. Are you proposing a rate plan in this filing?

A. Yes, the Company is proposing a multi-year rate plan with annual step adjustments to recover the revenue requirement of capital additions to rate base. The proposed 2021 Rate Plan is substantially similar to the plan that was established in Docket DE 16-381 (the "2016 Rate Plan"). The 2021 Rate Plan is outlined in detail in Schedule CGDN-1.

Q. What additions to plant will be eligible for recovery?

A. The plan will encompass three annual step adjustments to recover the revenue requirement. The step adjustments would take place in April of 2022, 2023 and 2024 for investment years 2021, 2022, and 2023. Each step adjustment compliance filing would be made with the Commission on or before the last day of January for the prior year's additions. Then, the resulting rate changes would go into effect April 1. For example, the filing for investment year 2021 additions would be filed with the Commission by January 30, 2022 with rates going into effect April 1, 2022, coinciding with the permanent rates from this proceeding. For investment year 1 (2021 additions), the new Exeter DOC plant additions through February 28, 2021 would be excluded from the 2021 Rate Plan, because the Company is requesting this as a proforma adjustment to rate base in the 2020 revenue requirement calculation with recovery starting in temporary rates effective June 1, 2021.

Q. Have you prepared a schedule to demonstrate the calculation of the Company's proposed 2021 Rate Plan?

A. Yes, we have prepared Schedule CGDN-2 Pages 1-3 for that purpose. The schedule is based on the Company's capital budget presented by Mr. Sprague. The schedule is for illustrative purposes, since actual plant additions will vary from the long-term forecast of the annual capital spending budget. Nevertheless, the schedule illustrates the express mechanics of the revenue requirement calculation.

Q. Please describe the derivation of Net Utility Plant on page 1 of Schedule CGDN-2.

A. Page 1 of Schedule CGDN-2 shows Beginning Utility Plant, Plant Additions, and Ending Utility Plant on lines 1-3. Beginning Utility Plant in 2021 corresponds to Schedule RevReq-4 pro forma rate base and includes a portion of the 2021 new Exeter DOC additions. Plant Additions are based on the capital budget, less new Exeter DOC additions through February 28, 2021, since those additions have been included in rate base in this proceeding. Ending Utility Plant is the sum of Beginning Utility Plant and Plant Additions. Then, lines 4-6 show Beginning Accumulated Depreciation, Depreciation Expense, and Ending Accumulated Depreciation. The difference between Ending Utility Plant and Ending Accumulated Depreciation results in Ending Net Utility Plant shown on line 7.

While Schedule CGDN-2 formulaically derives Net Utility Plant based on the capital budget provided in this proceeding, the intent of the Company is to source Net Utility Plant from its plant accounting records on an annual basis.

Q. Please describe the derivation of Revenue Requirement on page 1 of Schedule CGDN-2.

A. Once Net Utility Plant is sourced from the Company's plant accounting records, the annual Change in Net Plant would be calculated as the difference in Ending Net Utility Plant from the current period less the prior period as shown in line 8. Next, line 9 calculates the non-growth percent in Net Plant, which is the ratio of non-growth capital additions to total capital additions as derived by Mr. Kevin Sprague in his prefiled testimony. Then, line 10 is multiplied by line 11, pre-tax rate of return, to derive the Return and Taxes on line 12. Next, Depreciation Expense is calculated on the non-growth percent of Plant Additions (line 2). A composite depreciation rate of 3.36 percent will be used which corresponds to the Company's annualized depreciation rate, which was calculated by taking Line 36 Column 9 divided by Line 36 Column 7 from Schedule RevReq-3-16, Page 2. Then, Property Taxes are calculated on the non-growth Change in Net Plant (line 9). A composite property tax rate of 2.74 percent was used which was calculated by taking Line 36 Column 5 from Schedule RevReq-3-19 divided by Line 3 Column 5 from Schedule RevReq-4. The Company would update this rate annually based on the latest property tax rates. Finally, Return and Taxes, Depreciation Expense and Property Taxes are added together to arrive at the Revenue Requirement.

Q. What schedules support Schedule CGDN-2, Page 1?

A. Schedule CGDN-2, Page 2 presents the capital budget by year as well as depreciation by vintage that is used for calculating Accumulated Depreciation in Page 1 for illustrative purposes. Again, actual plant accounting records will be used in calculating Accumulated Depreciation to arrive at Net Utility Plant. Schedule CGDN-2, Page 3 shows the calculation of the pre-tax rate of return.

Q. How does the Company intend to incorporate the impact of New Hampshire House Bill ("HB") 700?

A. HB 700 established a methodology for valuing utility distribution assets for property tax purposes, codified as RSA 72:8-d and –e. The law established a new methodology for assessing utility property taxes, and a five-year phase-in period to fully transition to that new methodology. The first property tax year of the phase-in period is the tax year beginning April 1, 2020. The law also requires the Commission to establish by order a rate recovery mechanism for the property taxes paid by a public utility. The Company has recently made a filing in Docket No. DE 21-069 on March 29, 2020. Consistent with RSA 72:8-d and -e, property tax over- or under-recoveries as compared to the amount in base distribution rates shall be adjusted annually through the Company's EDC on August 1 of each year. The amount included in base distribution rates for property tax expense shall be

$7,771,772[1] based on property tax expense as of December 2021, as described above, normalized to exclude any credits related to property tax settlement proceeds for tax years preceding the test year. This amount would be updated annually as a part of the Company's EDC filing for the inclusion of property tax expenses to be recovered through the Company's 2021 Rate Plan. On an annual basis, actual property tax expense for the prior calendar year shall be compared against the amount in base rates and any variances will be reconciled through the EDC mechanism. Annual actual property tax expense shall be normalized to adjust for any credits received due to abatement settlement proceeds received for tax years preceding the test year. As proposed in Docket No. DE 21-069, the EDC shall recover any over- or under- recoveries beginning on August 1 of each year.

Q. Can you summarize the revenue requirement results for the proposed 2021 Rate Plan?

A. The revenue requirement that will be derived from the step adjustments ranges from $2.75 million (in investment year 2021) to $3.58 million (in investment year 2022) depending on the level of plant investments in a given forecast year. The step adjustments represent 1.7 percent to 2.3 percent of test year operating revenue. Again, these revenue requirement results are forecasts based on the Company's capital budget. Actual plant additions will vary from this forecast.

[1] Amount will be updated during the pendency of this proceeding to reflect the final 2021 tax bills.

Q. Would vegetation management and reliability enhancement O&M expenses continue to be reconciled?

A. Yes. The Company would continue to file annual compliance reports, and would continue to reconcile actual vegetation management and reliability enhancement O&M expenses to test year costs in the Company's EDC mechanism. With approval of the Commission, the Company may credit unspent amounts to future vegetation management program O&M expenditures.

Q. What is the amount of vegetation management and reliability enhancement O&M expenses embedded in the test year?

A. The amount of vegetation management and reliability enhancement O&M expenses embedded in the proforma test year is $6,265,166. Thus, the Company proposes to reconcile annually in the EDC mechanism the combined actual vegetation management and reliability enhancement spending to the combined test year expense of $6,265,166. The Company's request to recover vegetation management costs is not reduced by third party reimbursement related to the shared vegetation management costs for jointly-owned poles. As described in the prefiled testimony of Ms. Sara Sankowich, the Company's request to recover vegetation management costs is not reduced for these amounts because payment by the joint owners is not guaranteed nor always timely, and the integrity of the VMP should not be dependent upon the occurrence of these payments.

Q. How is the Company proposing to treat the contributions received from joint pole owners towards trimming expenses?

A. Any payment received from a joint pole owner will be credited to customers through the Company's EDC in the same manner that it is currently be credited to customers today.

Q. Are there consumer protections included in the 2021 Rate Plan?

A. Yes, as described earlier, the Company would submit an annual compliance filing subject to Commission review and approval. As outlined in Schedule CGDN-1, the Company proposes a limitation on the annual increase in revenues associated with the annual rate adjustments to 2.5 percent of total revenue, with revenue for externally supplied customers being adjusted by imputing the Company's default service charges for that period. Any part of the rate adjustment that exceeds 2.5 percent would be deferred for future recovery at the Company's cost of capital. The Company would also commit to a base rate case stay-out through 2024, subject to certain exogenous factors and considerations. The Company proposes an ROE collar which would allow the Company to file a base rate case before 2024 if ROE was under 7 percent, but provides for earnings sharing of 50 percent if ROE is greater than 11 percent. In addition, as with the 2016 Rate Plan, the 2021 Rate Plan includes features for exogenous events and excessive inflation.

V. TEMPORARY RATES

Q. Is the Company requesting that temporary rates be set in this proceeding?

A. Yes. The Company requests that temporary rates be established in the amount of $5,812,761 ($0.00501 per kWh) on an annualized basis to become effective on

June 1, 2021. The development of the temporary rate amount is detailed in Schedule CGDN-3.

Q. Please explain how the temporary rate amount of $5,812,761 ($0.00501 per kWh) was derived?

A. In general, we employed a conservative approach in calculating the amount of the temporary rate request. The amount of the temporary rate request was based on 2020 test year-end rate base with only one pro forma adjustment which keeps the lost base revenue recovery through the Company's SBC until the time permanent rates become effective as discussed in greater detail above. No other known and measurable adjustments relating to future costs are requested in the temporary rate increase. The cost of capital used in the calculation is based on the rate case filing capital structure and debt costs as provided in Schedule RevReq-5. However, the cost of equity was set lower at 9.50 percent reflecting the last authorized return on equity awarded to the Company in its last base rate case. As shown in page 2 of Schedule-CGDN-3, this results in an overall cost of capital of 7.61 percent.

Q. How does the Company account for and collect the difference between temporary rates and permanent rates once the Commission issues its order for permanent rates?

A. After the Commission issues its order in this case, the Company will submit a filing to collect the difference in revenue (or "recoupment") between temporary and permanent rates from the date temporary rates went into effect to the date permanent rates became effective. The recoupment surcharge will be a charge per kilowatt-hour, applied to all rate schedules, excluding electric vehicles rate classes. The Company expects to combine its recoupment with its rate case expenses which are explained in Section VIII.

VI. OTHER REGULATORY PROPOSALS AND CONSIDERATIONS

Q. What other proposals and considerations is the Company making?

A. The Company is requesting recovery of the first three items as part of the EDC, the fourth item be examined as part of a multi utility proceeding and the fifth item to be monitored during the pendency of the docket:

1. Waived Late Payment Charge Revenues for the period April 2020 through March 2021
2. Deferred Calypso Storm Costs
3. Incremental Wheeling Revenues
4. AHPA
5. Impact of RiverWoods Master Meter Plan (Docket No. DE 19-114)

We will discuss each adjustment individually in the following section.

1. WAIVED LATE PAYMENT CHARGES

Q. How has the Company been impacted by the New Hampshire emergency order prohibiting utility disconnections and application of utility late payment fees?

A. Yes, as a result of the shut off and late fee prohibition, UES was not able to apply late fees to customer’s accounts beginning in March of 2020. For the calendar year 2020, the Company charged $94,600 in late payment fees to customers which is well below the amount that was included when distribution rates were last set in Docket No. DE 16-384 and what the actual amount of late payment fees the Company would have charged to customers if the late payment fee prohibition was not in place.

Q. In Docket No. DE 16-384, what level of late payment charge revenues was included in the Company's distribution rates?

A. The level of late payment charge revenue included in the revenue requirement approved via settlement in that docket was $481,633. This amount was equal to the actual late payment charge revenues for 2015.

Q. How much late payment fees did the Company waive in 2020?

A. UES waived $444,121 of late payment fees for the 9 month period of April through December 2020 and is forecasted to waive approximately $583,000 of late payment fees for the 12 months ended March 31, 2021. Table 2 below provides a summary of the actual waived late fees waived by month for both time periods.

Table 2: Late Payment Fee Summary

Late Payment Charge ("LPC") Revenues
Unitil Energy Systems, Inc.

LPC Revenues	Docket No. DE 16-384 2015 (TY)	2020	Moratorium Period 2020	Moratorium Period 2020/2021	Comment
January	$ 32,521	$ 34,969			Charged - Actual
February	37,525	42,810			Charged - Actual
March*	67,162	16,898			Charged - Actual
April	36,974		$ 38,408	$ 38,408	Waived - Actual
May	53,102		50,008	50,008	Waived - Actual
June	51,970		50,302	50,302	Waived - Actual
July	30,390		49,107	49,107	Waived - Actual
August	39,352		60,052	60,052	Waived - Actual
September	36,271		52,415	52,415	Waived - Actual
October	31,310		58,729	58,729	Waived - Actual
November	33,997		47,201	47,201	Waived - Actual
December	31,059		37,900	37,900	Waived - Actual
January				42,430	Waived - Actual
February				46,621	Waived - Actual
March				*50,000*	Waived - Forecasted
Total LPC Revenues	$ 481,633	$ 94,676	$ 444,121	$ 583,173	

*Moratorium began in March 2020

Q. Is the $444,121 of waived late payment fees material to UES?

A. Yes, the amount is material to UES. For 2020, this amount represents roughly 4 percent of the Distribution Operating Income and 0.75 percent of the 2020 Test Year distribution revenues.

Q. What is the Company proposing related to recovery of the $444,121 of 2020 waived late payment fees?

A. For the 12 months ended December 31, 2020, the Company is proposing to recover $386,957, which is the difference between the actual late payment charge fees charged to customers in 2020 of $94,676 and the $481,633 amount included in rates in Docket No. DE 16-384. This amount is lower than the actual waived late payment fees amount of $444,121. The Company would propose that the $386,957 be recovered as part of the EDC.

Q. What is the Company proposing related to recovery of the waived late payment fees for 2021?

A. The Company is also proposing to recover the actual amount of waived payment fees as part of the EDC.

2. DEFERRED CALYPSO STORM COSTS

Q. Please provide a background summary of the deferred Calypso storm costs.

A. In docket DE 18-038, a dispute arose between the Company and the Commission's Audit Staff ("Audit") concerning the request for recovery of certain charges for the services of Calypso Communications in the Company's 2017 Annual Major Storm Cost Reserve Fund Report. Audit recommended removal of the charges from the MSCR, and the Commission adopted the recommendation. The Company requested rehearing and implementation of an adjudicative process. The dispute was resolved in a settlement agreement between the Staff and the Company, whereby the Company agreed to withdraw its request for rehearing and implementation of an adjudicatory process, and not seek any further proceeding in docket DE 18-038. The withdrawal was to be without prejudice to UES to request recovery of the disputed amount in its next filing seeking an increase in base rates. The Commission approved the settlement agreement in a Secretarial Letter Order issued on July 3, 2019. Since that time, similar issues of recovery of charges for Calypso Communications has arisen in subsequent annual MSCR filings (DE 19-040 and DE 20-043), and each time the Staff and the Company agreed that the request for recovery would be withdrawn without prejudice and would be resolved in the Company's next base rate proceeding.

Q. Please describe the nature of the charges from Calypso Communications.

A. The charges from Calypso Communications represent activities which are part of the Company's formal Emergency Response Plan ("ERP"), which has been submitted to the Commission on an annual basis in accordance with Rule Puc 306.09. The ERP, which (as required by Rule Puc 306.09(b)) utilizes the National Incident Management System (NIMS), has established the role of Chief Information Officer (CIO), reporting directly to the Incident Commander (IC). Information relative to storm/emergency preparation, customer interruptions, resource acquisitions, damage assessment, and restoration progress are to be managed by the communication protocols established under ICS and fashioned by the CIO team headed by the CIO.

Q. What are these activities for?

A. They represent tasks incurred to help the Company communicate timely and accurate information about restoration efforts regularly, consistently, and as widely as possible, and the product they produce provides evidence for cost recovery purposes. The Company's Communications team is responsible for keeping customers, media, local elected officials, local municipal officials and employees informed on safety issues, storm preparation and the status of restoration efforts during emergency conditions, such as storm events. It is critically important that timely and accurate information about restoration efforts be communicated as widely as possible. It is equally important that the Company communicate regularly prior to and throughout an emergency event and share information to ensure a consistent message is provided both internally and externally. It is also imperative that the Company fully document storm events as evidence for cost recovery purposes.

Q. Do the Calypso staff members undergo any training?

A. Yes. Unitil Service and Calypso have agreed to an emergency support protocol that is outside of any non-storm business retainers or project fees. This support is based on hours worked for storm preparation and response. Calypso Communications employees are trained throughout the year for specific storm roles and participate in all Unitil System-wide Annual Electric Drills to ensure they are prepared to respond to any and all emergency events at the same level as a Unitil Communications team member.

Q. Why can't these functions be performed by internal staff from the Company or Unitil Service?

A. Unitil Service's non-emergency Communications staff consists of eight full-time employees who are all part of the CIO team during emergency events. However, during emergency events the Media, Employee and Digital Communications section of the CIO expands to include contracted communications support, specifically from Calypso Communications. It is critical that the CIO team communications support have experience and skill in specific communications functions such as media and digital communications. Calypso Communications' staff members are given assignments as members of the CIO team, which allow for all CIO Communications storm roles to be staffed for the duration of an event in two shifts. Calypso staff members have assisted with pre-storm preparation and communication by participating in all pre-storm conference calls as part of our CIO team protocols and Calypso team members staffed shifts during the storm responses covering media relations support, social media support and web/photo/video support. The internal Unitil Communications team, or other internal staff who are responsible for various other critical functions during emergency operations, would not be able to cover all roles and shifts during an emergency event without the additional support provided by trained Calypso staff.

Q. What is the Company proposing related to recovery of the deferred Calypso storm costs?

A. The Company is proposing to recover the deferred Calypso storm costs through its EDC over a one year period.

Q. What is the Company's proposal regarding the treatment of future storm-related Calypso costs?

A. The Company proposes that these costs, as they are based solely on hours worked for storm preparation and response, should be allowed to be recovered through the MSCR, which is specifically designed "to recover costs associated with responding to and recovering from qualifying major storms." (Settlement Agreement, DE 10-055 at paragraph 8.1)

3. INCREMENTAL WHEELING REVENUES

Q. Has the Company included wheeling revenues in the calculation of the overall revenue requirement?

A. Yes, the test year other operating revenues reflect $49,952 of wheeling revenues primarily associated with a legacy wheeling agreement that is ending on April 20, 2021.

Q. What services are provided by UES that generate wheeling revenues?

A. Wheeling fees are charged to generators for the transfer of power across UES's distribution system to compensate customers for the use of the system. Under the legacy wheeling agreement that will terminate on April 20, 2021, the generator has paid UES a FERC-approved, mutually agreed-upon rate during the contract term for wheeling services.

Q. What will happen once the wheeling agreement terminates?

A. Upon termination of the wheeling agreement, the outside generator will have the option to sell power as a Qualified Facility pursuant to UES's tariff (Schedule QF) and Federal Public Utility Regulatory Policies Act (PURPA) Section 210 or continue to transfer power across UES's distribution system to a third party or parties pursuant to a FERC-approved wheeling rate. The Company is in the process of finalizing a filing that will be submitted to FERC proposing

Distribution wheeling rates that will be available to generators seeking to wheel power across the UES distribution system.

Q. What is the Company proposing related to wheeling revenues?

A. Due to the uncertainty related to whether the wheeling revenues will increase or decrease in the future, the Company is proposing to annually reconcile the actual wheeling revenues included in the test year of $49,952 compared to the actual wheeling revenues for the calendar year and refund or collect the difference through the subsequent year's EDC. This will ensure that customers receive the full value associated with generators utilizing the system for wheeling power. If the proposal to track increases in the wheeling revenues as part of the EDC is not accepted, then a proforma adjustment to remove the $49,952 of wheeling revenues from the revenue requirement would be required to reflect the ending of the wheeling agreement on April 20, 2021.

4. ACTIVE HARDSHIP PROTECTED ACCOUNTS

Q. Please define the phrase "Active Hardship Protected Accounts" and "Active Hardship Protected Receivables."

A. Active Hardship Protected Accounts are residential service accounts that, in accordance with the New Hampshire Code of Administrative Rules, Chapter Puc 1200, are protected from disconnection by the utility for non-payment under the hardship provisions of Part 1205 Medical Emergency Rules. Active Hardship Protected Receivables are receivable balances owed to the Company by Active Hardship Protected Accounts. Since the Company's last rate case, the Company has continue to see a substantial increase in both the number of customers and the past due accounts receivable balances of customers protected from disconnection under the Medical Emergency Rules.

Q. Please describe the hardship protections available to the Company's customers under Part Puc 1205.

A. Part Puc 1205 protects residential customers who have a medical emergency (as defined in Puc 1202.12) from having their service disconnected. Specifically, a utility may not disconnect service to a customer who has provided current verification of a medical emergency and is complying with a payment arrangement. Puc 1205.03(a). However, if a customer does not enter into or comply with the terms of a payment arrangement consistent with Commission rules, a utility may request permission to disconnect service to the customer. Puc 1205.03(b). The process for seeking disconnection requires, among other things, that the customer be given concurrent written notice and an opportunity to respond to the utility's request. Puc 1205.03(c).

Q. What did the Company propose in its last rate case in Docket No. DE 16-384 related to an AHPA?

A. In Docket No. DE 16-384, the Company submitted a proposal to recover the costs of its past due and uncollectible hardship receivables. Specifically, the Company proposed to recover costs of writing down AHPA, while maintaining the amounts for credit and collection purposes. AHPA receivables result from customers that are in special circumstances which require specific credit and collection and cost recovery policies, which protect these customers from having their service disconnected and their receivables written off and recovered through normal bad debt expense. The Company's proposal allowed for the recovery of uncollectible AHPA receivables.

Q. Was the Company's AHPA proposal approved in Docket No. DE 16-384?

A. The rate case resulted in a settlement with the NHPUC Staff, OCA and the Company. The AHPA was not implemented as part of the settlement agreement, but was addressed in Section 7.5 of the approved settlement.

Q. How was the AHPA proposal addressed in the settlement?

A. The AHPA was addressed in Section 7.5 of the Settlement Agreement, which stated:

> The Settling Parties agree that Unitil shall withdraw, without prejudice, its proposal to recover the bad debt expense for uncollectible accounts receivable due from its Active Hardship Protected Accounts (AHPA). In this proceeding, Unitil had proposed to recover AHPA bad debt expense through the amortization, over a five year period, of a regulatory asset established based on the over-360 days past due balance of AHPA at December 31, 2015, in order to write these balances off for accounting purposes while maintaining the balances as due and payable for customer billing and credit and collection purposes. Unitil also committed to tracking and reporting to the Commission the activity of the AHPA balances during the five year period. Staff testified that the continued increase in the number of residential accounts and the accounts receivable balances of those accounts which are protected through the Medical Emergency procedures in Puc 1205, which do allow utilities a process to disconnect service to customers in non-life threatening situations, is an issue which affects all utilities in New Hampshire. Accordingly, rather than addressing this issue on an individual utility case-by-basis, the Settling Parties hereby recommend that the Commission open a generic proceeding to develop a common approach to this issue, within six months of the approval of this Settlement. The Settling Parties acknowledge that if no generic proceeding takes place, Unitil will again propose recovery of

its over-360 day past due AHPA bad debt expense in its next base rate proceeding.

Q. Was a generic proceeding opened?

A. No, a proceeding was not opened.

Q. Do the Active Hardship Accounts continue to be a concern for the Company?

A. Yes. As can be seen in Table 3 below, although the year over year growth of the protected receivables has slowed since the last rate case, they have increased by 67 percent since the 2015 Test Year in the last rate case.

Table 3: Active Hardship Protected Accounts

Line No.	Dec. 31,	Total A/R	Under 120 Days	120-360 Days	Over 360 Days		Over 360 Annual Increase	Over 360 % Increase	# Customers Over 360 Days
		(a)	(b)	(c)	(d)		(e)	(f)	(g)
1	**2011**	$ 617,596	$138,684	$191,520	$ 287,392				127
2	**2012**	884,779	177,152	246,539	461,088		$173,696	60%	175
3	**2013**	1,052,022	181,412	239,771	630,839		169,751	37%	194
4	**2014**	1,393,560	248,098	345,916	799,546		168,707	27%	211
5	**2015**	1,682,347	238,583	518,681	925,083	(1)	125,537	16%	230
6	**2016**	1,615,747	211,721	380,698	1,023,328		98,245	11%	230
7	**2017**	1,646,651	141,522	370,778	1,134,351		111,022	11%	226
8	**2018**	2,187,768	241,197	560,276	1,386,295		251,944	22%	300
9	**2019**	2,294,182	216,909	603,603	1,473,670		87,375	6%	316
10	**2020**	2,226,464	184,821	495,001	1,546,642	(1)	72,972	5%	283
			Average Increase 2017 to 2020				**$130,829**		

(1) $1,546,642 - $925,083 = $621,559; $621,559 / $925,083 = 67%

Q. Is the Company proposing a recovery mechanism associated with the Medically Protected Hardship Accounts consistent with the proposal it made in the last rate case filing in Docket No. DE 16-384?

A. Not at this time. The Company is requesting that when an order is issued in this proceeding that the order includes and order opening a separate statewide utility proceeding to address the ongoing concerns related to the Active Hardship Protected Accounts.

5. RIVERWOODS MASTER METER PLAN

Q. Is the Company aware of the RiverWoods plan to master meter their campus?

A. Yes. In Docket No. DE 19-114, RiverWoods petitioned the Commision for a waiver of the restrictions on master metering and was subsequently granted the waiver via a Secretarial Letter issued on March 11, 2020.

Q. Has the master metering conversion been completed?

A. No. The Company has been notified by Riverwoods that it expects to complete this project by the end of 2021.

Q. What impact will the conversion have on the Company?

A. Currently the Company has approximately 200 separate residential meters at the facility. Once the master metering conversion is completed the 200 meters will be replaced by 3 or 4 Rate G2 small general meters. The exact configuration is not known at this time. If the conversion moves forward, the Company will need to adjust test year revenues and billing determinants to reflect the change associated with going from 200 residential meters to 3 or 4 Rate G2 small general meters.

Q. Why has the Company not already reflected this adjustment?

A. Due to the project being in its early stages, the Company does not have all of the necessary details in order to make an accurate adjustment at this time. Once final plans are completed for the conversion and it is known that the conversion will occur, the Company would make the necessary proforma adjustments.

VII. TRANSITION TO DECOUPLING

Q. How will the Company transition from Lost Revenue Recovery ("LRR") as part of the Systems Benefit Charge ("SBC") to Decoupling?

A. At the start of the proposed decoupling period of April 1, 2022, the Company will stop accruing LBR associated with Energy Efficiency savings but up until that time, the Company would need to continue to collect and accrue LBR associated with the 2020 energy efficiency savings, the 2021 energy efficiency savings and the 2022 energy efficiency savings through March 31, 2022 assuming a start date of decoupling of April 1, 2022. Table 4 below outlines how the transition will work based on the proposed temporary rates, permanent rates and decoupling start period of April 1, 2022 timeline. The Company is not proposing any change to the SBC rate at this time and instead will make all required changes, including reconciliations in subsequent SBC filings as appropriate.

Table 4: Transition from LBR to Decoupling

June 1, 2021 (Temporary Rates Effective)
Stop accruing lost revenue associated with the 2017 savings
Stop accruing lost revenue associated with the 2018 savings
Stop accruing lost revenue associated with the 2019 savings
Continue accruing lost revenue associated with the 2020 savings*
Continue accruing lost revenue associated with the 2021 savings
January 1, 2022 to March 31, 2022
Continue accruing lost revenue associated with the 2020 savings*
Continue accruing lost revenue associated with the 2021 savings
Continue accruing lost revenue associated with the 2022 savings
April 1, 2022 (Permanent Rates Effective - Begin Decoupling)
Stop accruing lost revenue associated with the 2020 savings*
Stop accruing lost revenue associated with the 2021 savings
Stop accruing lost revenue associated with the 2022 savings
*Taking into account timing of the month of installtion for the 2020 measures

Q. Why will the Company continue to accrue lost revenue associated with the 2020 measures if 2020 was the test year?

A. The Company needs to continue to recover lost revenue associated with the savings reduction not reflected in the 2020 test year. For example, for a measure that was installed in December 2020 that is estimated to save 120 kWh annually, the impact on the 2020 test year sales would only reflect a reduction of 12 kWh (120 / 12 months * 1 month), and the remaining 108 kWh of savings would be realized in 2021 so it is necessary to continue to recover lost revenue associated with the 2020 savings taking into account the month that savings were realized in 2020. Table 5 below shows an illustrative example of how the calculation would work assuming 3,214,309 kWh of annual 2020 savings installed evenly throughout the year. The 2020 test year would reflect a reduction in sales of 1,741,084 kWh with the remaining reduction of 1,473,225 kWh of savings reduction occurring in 2021.

Table 5: Illustrative 2020 Savings Annualization

Unitil Energy System, Inc.
2020 Residential Installed kWh Savings
Savings Annualization

Line	Description	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	2020 Annual Savings
	Col. A	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O
1	**Monthly Residential kWh Savings**	**267,859**	**267,859**	**267,859**	**267,859**	**267,859**	**267,859**	**267,859**	**267,859**	**267,859**	**267,859**	**267,859**	**267,859**	**3,214,309**
2														
3	**Monthly Residential Annualized kWh Savings**													
4	January 2020	22,322	22,322	22,322	22,322	22,322	22,322	22,322	22,322	22,322	22,322	22,322	22,322	267,859
5	February 2020		22,322	22,322	22,322	22,322	22,322	22,322	22,322	22,322	22,322	22,322	22,322	245,537
6	March 2020			22,322	22,322	22,322	22,322	22,322	22,322	22,322	22,322	22,322	22,322	223,216
7	April 2020				22,322	22,322	22,322	22,322	22,322	22,322	22,322	22,322	22,322	200,894
8	May 2020					22,322	22,322	22,322	22,322	22,322	22,322	22,322	22,322	178,573
9	June 2020						22,322	22,322	22,322	22,322	22,322	22,322	22,322	156,251
10	July 2020							22,322	22,322	22,322	22,322	22,322	22,322	133,930
11	August 2020								22,322	22,322	22,322	22,322	22,322	111,608
12	September 2020									22,322	22,322	22,322	22,322	89,286
13	October 2020										22,322	22,322	22,322	66,965
14	November 2020											22,322	22,322	44,643
15	December 2020												22,322	22,322
16	**Total 2020 Savings Realized in 2020**	**22,322**	**44,643**	**66,965**	**89,286**	**111,608**	**133,930**	**156,251**	**178,573**	**200,894**	**223,216**	**245,537**	**267,859**	**1,741,084**
17														
18	**2020 Residential kWh Savings Realized in 2021**	**-**	**22,322**	**44,643**	**66,965**	**89,286**	**111,608**	**133,930**	**156,251**	**178,573**	**200,894**	**223,216**	**245,537**	**1,473,225**

VIII. PROPOSED TARIFF CHANGES

Q. Please summarize the proposed tariff changes presented in the Company's filing.

A. The Company's proposed tariff changes reflect (1) the proposed rates, including new Light Emitting Diode "LED" rates proposal as presented in the prefiled testimony of John Taylor, (2) the proposed Revenue Decoupling Adjustment Clause as presented in the prefiled testimony of Timothy Lyons, (3) proposed changes to the Company's EDC tariff and (4) changes to the Company's distribution terms and conditions as supported by Mark Lambert. The Company has also provided illustrative Time of Use Tariffs as Exhibits to the prefiled testimony of Cindy Carroll, Carleton Simpson, and Carol Valianti.

Q. What changes is the Company proposing to the EDC tariff, Schedule EDC?

A. The Company is proposing changes to its existing approved EDC tariff to address the following:

1. As described above in Section III. C. ii. 13, the Company is proposing to track the actual delivery write offs against the level in distribution rates and to recover the difference annually as part of the subsequent years EDC.
2. The Company is proposing to track the actual annual cost of the AMP and reconcile the cost annually against the amount that is included in base distribution rates. Any variance from the level in distribution rates will be deferred and refunded or recovered as part of the subsequent years EDC. This is described in greater detail in Section III. C. ii. 14 above.
3. As described in Section VI. 1 above, the Company is proposing to refund or collect the late payment fees the Company would have charged to customers if the late payment fee prohibition was not in place through the subsequent year's EDC.
4. The Company is proposing to collect the Deferred Calypso Storm Charges as described in Section VI. 2 through the Company's EDC over a one year period.
5. The Company is proposing to annually reconcile the actual wheeling revenues included in the test year compared to the actual revenues for the calendar year and refund or collect the difference through the subsequent year's EDC. This is described in greater detail in Section VI. 3 above.

6. Finally the Company is proposing to recover the Incentive Program and Marketing, Communications, and Education costs through the EDC. These costs are described in the prefiled testimony of Cindy Carroll, Carleton Simpson, and Carol Valianti. The Company will include an estimate of these costs in the annual EDC filing which would be reconciled to actual costs through the subsequent years EDC.

The Company has proposed to track and recover the incremental change in local property taxes as described in greater detail in Section IV and as a part of its filing in Docket No. DE 21-069 on March 29, 2021.

Finally, the Company is not proposing any change to the EDC rate at this time and instead will make all required changes, including reconciliations in subsequent EDC filings as appropriate.

Q. Has the Company prepared revised tariffs?

A. Yes. The clean and red-lined versions of the proposed tariff changes have been provided as a part of this filing.

Q. Are there any other tariff changes resulting from this case?

A. Yes. UES will file a rate case surcharge tariff at the conclusion of this proceeding to recover rate case costs and the recoupment and reconciliation of temporary and permanent rates when the final amounts are known.

IX. RATE CASE EXPENSES

Q. How do you propose to recover rate case expenses?

A. UES proposes to file a rate case surcharge to recover the costs incurred to plan, develop and present this rate case to the Commission at the conclusion of this proceeding when the final dollar amount of these expenses is known. A projection of these costs is detailed in Schedule RevReq-6.

Q. How do you propose to structure the rate case expenses surcharge?

A. The rate case expenses surcharge will be a charge per kilowatt-hour, applied to all rate schedules. Subject to Commission approval, the charge will be a temporary charge, and will be set at a level to recover the costs over a one-year period. The revenue collected will be fully reconciled with the costs incurred. At the end of the recovery period, the Company would file with the Commission a reconciliation of the surcharge, including a recommendation for treatment of any under- or over-recovered balances projected to remain at the end of the surcharge account.

Q. Please provide the estimated amount of rate case costs.

A. The estimated costs to be incurred for the rate case are $755,000 and are detailed on Schedule RevReq-6.

Q. How does the Company account for rate case costs?

A. The Company defers all costs associated with the case as they are incurred during the course of the proceeding for future recovery in rates. The Company is prepared to provide the Commission's audit staff with documentation to support those costs eligible for recovery. This documentation will consist of copies of invoices and/or other information that will assist the Commission Staff with its audit.

Q. Will the Company inform the Commission about its actual rate case costs throughout this proceeding?

A. Yes, every 90 days the Company will file with the Commission the items required by Part Puc 1905.01 (a) of its rules.

X. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

Unitil Energy Systems, Inc.
DE 21-030
Filing Requirement Schedules

UNITIL ENERGY SYSTEMS, INC
NEW HAMPSHIRE FILING REQUIREMENT SCHEDULES
TABLE OF CONTENTS

UNITIL ENERGY SYSTEMS, INC
SCHEDULE - COMPUTATION OF REVENUE DEFICIENCY
12 MONTHS ENDED DECEMBER 31, 2020

	(1)	(2)	(3)	
LINE NO.	DESCRIPTION	REFERENCE	AMOUNT	
1	Rate Base	Schedule RevReq-4	$	226,030,082
2	Rate Of Return	Schedule RevReq-5		7.88%
3	Income Required	Line 1 * Line 2		17,811,170
4	Adjusted Net Operating Income	Schedule RevReq-2		9,066,677
5	Deficiency	Line 3 - Line 4		8,744,493
6	Income Tax Effect	Line 7 - Line 5		3,247,900
7	Revenue Deficiency	1.3714 (Schedule RevReq-1-1) * Line 5	$	11,992,392

UNITIL ENERGY SYSTEMS, INC
OPERATING INCOME STATEMENT
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO.	(1) DESCRIPTION	(2) TEST YEAR 12 MONTHS ENDED 12/31/2020	(3) TEST YEAR FLOW-THROUGH	(4) TEST YEAR DISTRIBUTION	(5) PROFORMA ADJUSTMENTS	(6) TEST YEAR DISTRIBUTION AS PROFORMED	0 0 0	(7) CALENDAR YEAR 2019 (1)	(8) CALENDAR YEAR 2018 (1)
1	Distribution Revenue	$ 58,337,364	$ -	$ 58,337,364	$ (280,812)	$ 58,056,553		$ 57,749,747	$ 57,757,766
2	Flow-Through Revenue	98,489,216	98,489,216	-	-	-		101,655,415	97,267,289
3	Electric Service Revenue	156,826,580	98,489,216	58,337,364	(280,812)	58,056,553		159,405,162	155,025,055
4	Other Operating Revenue	2,096,875	1,078,347	1,018,528	493,945	1,512,473		2,426,664	2,623,127
5	Total Operating Revenues	158,923,455	99,567,563	59,355,892	213,133	59,569,025		161,831,826	157,648,182
6	Operating Expenses:								
7	Purchased Power	53,020,521	52,736,269	284,252	-	284,252		65,385,884	61,038,767
8	Transmission	35,468,734	35,400,175	68,559	-	68,559		28,308,204	29,608,490
9	Distribution	9,476,199	-	9,476,199	2,113,975	11,590,175		9,195,883	9,199,438
10	Customer Accounting	4,286,916	321,671	3,965,244	449,940	4,415,184		4,655,167	4,633,933
11	Customer Service	7,326,955	7,298,180	28,775	-	28,775		5,450,371	3,773,461
12	Administrative & General	9,750,830	825,374	8,925,457	1,006,161	9,931,618		10,867,236	10,763,947
13	Depreciation	12,680,791	-	12,680,791	118,963	12,799,754		11,905,213	11,419,121
14	Amortizations	3,262,428	1,059,270	2,203,158	(761,204)	1,441,954		3,378,749	3,484,160
15	Taxes Other Than Income	7,166,678	-	7,166,678	905,507	8,072,185		6,435,130	6,519,710
16	Federal Income Tax (3)	(1,180,388)	-	(1,180,388)	3,523,246	2,342,858		4,672,111	(173,832)
17	State Income Tax (3)	(1,096,468)	-	(1,096,468)	1,264,624	168,156		1,707,349	(927)
18	Deferred Federal & State Income Taxes	5,203,294	-	5,203,294	(5,861,441)	(658,148)		(3,692,668)	3,207,039
19	Interest On Customers Deposits	17,026	-	17,026	-	17,026		31,594	32,204
20	Total Operating Expenses	145,383,515	97,640,939	47,742,577	2,759,771	50,502,348		148,300,222	143,505,511
21	Net Operating Income	$ 13,539,940	$ 1,926,625	$ 11,613,315	$ (2,546,638)	$ 9,066,677		$ 13,531,604	$ 14,142,671

Notes
(1) Calendar Years 2019 and 2018 Represents Total Company (i.e., Flow-Through and Distribution).

UNITIL ENERGY SYSTEMS, INC
SCHEDULE 1 ATTACHMENT - PROFORMA ADJUSTMENT INCOME OR EXPENSE
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO.	(1) DESCRIPTION	(2) CLASSIFICATION	(3) SCHEDULE NO.	(4) AMOUNT
1	Revenue Adjustments			
2	Non-Distribution Bad Debt	Dist Rev	Schedule RevReq-3-1	(143,623)
3	Unbilled Revenue Adjustment	Dist Rev	Schedule RevReq-3-1	(137,189)
4	New DOC Rent Revenue	Oth Rev	Schedule RevReq-3-1	313,007
5	Late Fee Adjustment	Oth Rev	Schedule RevReq-3-1	180,938
6	Total Revenue Adjustments			$ 213,133
7	Operating & Maintenance Expense Adjustments			
8	Payroll	Dist	Schedule RevReq-3-2	$ 709,516
9	VMP Expense	Dist	Schedule RevReq-3-3	1,406,427
10	Medical & Dental Insurances	A&G	Schedule RevReq-3-4	483,155
11	Pension	A&G	Schedule RevReq-3-5	62,288
12	PBOP	A&G	Schedule RevReq-3-5	(41,636)
13	SERP	A&G	Schedule RevReq-3-5	85,989
14	401K	A&G	Schedule RevReq-3-5	41,844
15	Deferred Comp Expense	A&G	Schedule RevReq-3-5	64,957
16	Property & Liability Insurances	A&G	Schedule RevReq-3-6	72,468
17	DOC Expense Adjustment	Dist	Schedule RevReq-3-7	(1,968)
18	NHPUC Regulatory Assessment	A&G	Schedule RevReq-3-8	159,383
19	Dues & Subscriptions	A&G	Schedule RevReq-3-9	(14,473)
20	Pandemic Costs	A&G	Schedule RevReq-3-10	(39,857)
21	Claims & Litigation Adjustment	A&G	Schedule RevReq-3-11	44,072
22	Severance Expense	A&G	Schedule RevReq-3-12	(40,395)
23	Distribution Bad Debt	Cust Acct	Schedule RevReq-3-13	134,563
24	Non-Distribution Bad Debt	Cust Acct	Schedule RevReq-3-1	(143,623)
25	Arrearage Management Program (AMP) Implementation Cost	Cust Acct	Schedule RevReq-3-14	459,000
26	Inflation Allowance	A&G	Schedule RevReq-3-15	128,368
27	Total Operating & Maintenance Expense Adjustments			$ 3,570,077
28	Depreciation & Amortization Expense Adjustments			
29	Depreciation Annualization	Depr	Schedule RevReq-3-16 P1	$ 908,712
30	Proposed Depreciation Rates	Depr	Schedule RevReq-3-16 P2	(789,749)
31	Software Amortization	Amort	Schedule RevReq-3-17	238,591
32	Excess ADIT Flowback	Amort	Schedule RevReq-3-18	(999,795)
33	Total Depreciation & Amortization Expense Adjustments			$ (642,241)
34	Taxes Other Than Income Adjustments			
35	Property Taxes	Taxes Other	Schedule RevReq-3-19	$ 744,985
36	Payroll Taxes - Wage Increases	Taxes Other	Schedule RevReq-3-20 P1	54,278
37	Payroll Taxes - Employee Retention Credit	Taxes Other	Schedule RevReq-3-20 P2	106,244
38	Total Taxes Other Than Income Adjustments			$ 905,507
39	Income Taxes Adjustments			
40	Federal Income Tax	FIT	Schedule RevReq-3-21 P1	$ (770,033)
41	State Income Tax	SIT	Schedule RevReq-3-21 P1	(305,900)
42	Prior Year Federal Income Tax	FIT	Schedule RevReq-3-21 P4	4,293,279
43	Prior Year State Income Tax	SIT	Schedule RevReq-3-21 P4	1,570,523
44	Prior Year Deferred Federal Income Tax	DIT	Schedule RevReq-3-21 P4	(4,290,918)
45	Prior Year Deferred State Income Tax	DIT	Schedule RevReq-3-21 P4	(1,570,523)
46	Total Income Taxes Adjustments			$ (1,073,571)
47	Rate Base Adjustments			
48	Cash Working Capital Adjustment	CWC	Schedule RevReq-4-2	$ 967,154
49	Kensington Distribution Operating Center Adj. - Net Book Value	Plant	Schedule RevReq-4-3	(988,214)
50	Kensington Distribution Operating Center Adj. - ADIT	RB DIT	Schedule RevReq-4-3	(71,351)
51	Exeter Distribution Operating Center Adj. - Net Book Value	Plant	Schedule RevReq-4-4	577,144
52	Excess Accumulated Income Tax Adj. (Storm)	EDIT	Schedule RevReq-4-5	(2,644,590)
53	Accumulated Deferred Income Tax Adj. (Storm)	EDIT	Schedule RevReq-4-5	716,234
54	Total Rate Base Adjustments			$ 2,555,790

UNITIL ENERGY SYSTEMS, INC
SCHEDULE 1A - PROPERTY TAXES
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO.	(1) MUNICIPALITY & STATE	(2) TAXATION PERIOD	(3) LOCAL TAX RATE	(4) ASSESSED VALUATION	(5) TOTAL TAXES[1]
1	Allenstown	4/1 - 3/31	$ 27.27	$ 72,800	$ 1,985
2	Atkinson	1/1 - 12/31	16.24	6,404,700	104,012
3	Boscawen	4/1 - 3/31	24.91	9,837,900	245,062
4	Bow	4/1 - 3/31	23.69	13,389,400	317,195
5	Brentwood	4/1 - 3/31	21.36	189,400	4,046
7	Chichester	1/1 - 12/31	21.27	5,774,800	122,830
8	Concord	7/1 - 6/30	24.89	61,631,200	1,534,001
9	Concord	7/1 - 6/30	26.76	83,600	2,237
10	Concord	7/1 - 6/30	28.13	10,358,200	291,376
11	Danville	4/1 - 3/31	24.14	3,885,600	93,798
12	Dunbarton	4/1 - 3/31	20.40	565,000	11,526
13	East Kingston	4/1 - 3/31	20.50	6,782,600	139,043
14	Epsom	4/1 - 3/31	19.92	4,750,000	94,620
15	Exeter	4/1 - 3/31	24.49	613,300	15,020
16	Exeter - Land Only	4/1 - 3/31	22.50	23,387,900	526,228
17	Greenland	4/1 - 3/31	14.58	30,500	445
18	Hampstead	4/1 - 3/31	19.63	464,700	9,122
19	Hampton--Class 4000	4/1 - 3/31	13.93	22,489,300	313,276
20	Hampton--Class 5000	4/1 - 3/31	14.43	11,076,800	159,838
21	Hampton Falls	4/1 - 3/31	19.33	4,260,400	82,354
22	Hopkinton	4/1 - 3/31	27.41	477,700	13,094
23	Kensington	4/1 - 3/31	18.61	10,060,284	187,222
24	Kingston	4/1 - 3/31	18.94	19,784,300	369,094
25	Loudon	4/1 - 3/31	20.73	616,800	12,786
26	Newton	4/1 - 3/31	19.10	6,078,600	116,101
27	North Hampton	4/1 - 3/31	14.80	137,300	2,032
28	Pembroke	4/1 - 3/31	22.77	421,800	9,604
29	Plaistow	4/1 - 3/31	19.60	15,501,960	303,838
30	Salisbury	4/1 - 3/31	22.55	2,689,000	60,637
31	Seabrook	4/1 - 3/31	13.90	19,802,000	275,249
32	South Hampton	4/1 - 3/31	17.14	2,572,400	44,091
33	Stratham	4/1 - 3/31	17.14	9,749,400	167,105
34	Webster	4/1 - 3/31	20.28	2,838,900	57,573
35	State Property Tax[2]	4/1 - 3/31	-	-	1,644,889
36	Total			$ 279,903,944	$ 7,410,651
37	Plus: New Exeter DOC Adjustment[3]			$ 15,517,171	$ 380,016
38	Less: Removal of Old Kensington DOC			$ 1,015,306	$ 18,895
39	Adjusted Test Year Property Tax Expense				$ 7,771,772
38	Test Year Property Taxes [4] [5]				$ 7,065,052
39	Less: Test Year Property Tax Abatements [4]				38,265
40	Total Test Year Property Tax Expense				$ 7,026,787
41	Total Property Tax Increase (Line 39 - Line 40)				$ 744,985

Notes
(1) Based on final 2020 property tax bills. Company will update for final 2021 property tax bills during pendency of case
(2) Based on current estimated 2021 State Property Tax. Amount will be updated during pendency of case
(3) Estimated Exeter DOC valuation to be updated with actual town valuation during proceeding
(4) Test Year Property Taxes (Line 38) adjusted to exclude inadvertent property tax abatement entry of $4,172.67. This amount was included in the Property Tax Abatements (Line 39) to correct
(5) Test Year Property Taxes reduced by $12,230.60 to remove accrual adjustment entry related to 2019

UNITIL ENERGY SYSTEMS, INC
SCHEDULE 1B - PAYROLL
12 MONTHS ENDED DECEMBER 31, 2020

	(1)	(2)	(3)	(4)	(5)	(6)
LINE			UES		FROM	
NO.	DESCRIPTION	NONUNION	UNION	SUBTOTAL	USC	TOTAL
1	Test Year Payroll, Adjusted for Target Incentive Compensation	$ 1,405,138	$ 4,793,090	$ 6,198,228	$ 8,630,554	$ 14,828,782
2	2020 Rate Increase, Annualized (1)	-	57,518	57,518	-	57,518
		-	-	-	-	-
3	Payroll Annualized for 2020 Union Wage Increase	1,405,138	4,850,608	6,255,746	8,630,554	14,886,300
4	2021 Salary & Wage Increase (2)	51,288	145,518	196,806	379,744	576,550
5	Payroll Proformed for 2020 and 2021 Wage Increases	1,456,426	4,996,126	6,452,552	9,010,298	15,462,850
6	2022 Salary & Wage Increase (3)	53,160	149,884	203,043	396,453	599,496
7	Payroll Proformed for 2020, 2021 and 2022 Wage Increases	1,509,585	5,146,010	6,655,595	9,406,751	16,062,346
8	Less Amounts Chargeable to Capital(4)	969,908	3,306,311	4,276,219	2,676,221	6,952,440
9	O&M Payroll Proformed	539,677	1,839,699	2,379,376	6,730,530	9,109,907
10	Less: Test Year O&M Payroll(5)			2,225,229	6,175,162	8,400,391
11	Increase in O&M Payroll due to Annual Salary and Wage Increases			154,147	555,368	709,516
12	Incentive Compensation Target Adjustment(6)			$ -	-	-
13	Net Adjustment to O&M Payroll / Compensation			154,147	555,368	709,516

Notes

(1) UES Union increase of 3.0% effective June 1, 2020
(2) UES Non-union increase of 3.65% effective January 1, 2021, Union increase of 3.0% effective June 1, 2021 and USC increase of 4.40% effective January 1, 2021
(3) UES Non-union increase of 3.65% effective January 1, 2022, Union increase of 3.0% effective June 1, 2022 and USC increase of 4.40% effective January 1, 2022
(4) Test Year Payroll Capitalization Rates:

UES	64.25%
USC	28.45%

(5) Refer to Workpaper 2.2 and Schedule RevReq-3-2, page 2.
(6) Refer to Workpaper 2.4

UNITIL ENERGY SYSTEMS, INC
SCHEDULE 2 - ASSETS & DEFERRED CHARGES
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO.	(1) Category		(3) Year Ended December 31, 2020		(2) 13 Monthly Average Ended December 31, 2020
1	Electric Plant				
2	In Service	$	408,325,135	$	374,519,479
3	Construction Work in Progress		5,132,123		24,080,907
4	Less: Reserve for Depreciation		(138,059,087)		(136,315,421)
5	Total Electric Plant		275,398,170		262,284,966
6	Other Property				
7	Total Other Net Property		50,606		50,606
8	Total Other & Non Operating Plant		50,606		50,606
9	Current Assets				
10	Cash		363,677		(65,394)
11	Other Special Deposits (ISO Deposit)		2,243,895		2,295,378
12	Working Funds		3,000		3,002
13	Accounts Receivable		18,946,030		18,007,279
14	Accounts Receivable - Other		302,295		290,140
15	Uncollectible Accounts		(556,372)		(219,356)
16	Accts Receivable - Assoc. Companies		6,113,320		2,343,267
17	Material and Supplies		1,206,272		1,272,431
18	Stores Expense Undistributed		201,952		152,401
19	Prepayments		6,012,559		5,682,503
20	Accrued Revenue		12,242,701		9,119,205
21	Miscellaneous Current Assets		146,491		130,538
22	Total		47,225,819		39,011,394
23	Deferred Charges				
24	Unamortized Debt Expense		1,254,801		1,179,594
25	Other - Deferred Debits		41,008,223		31,001,441
26	Total Deferred Charges		42,263,024		32,181,035
27	Total Assets & Deferred Charges	$	364,937,619	$	333,528,001

UNITIL ENERGY SYSTEMS, INC
SCHEDULE 2A - STOCKHOLDERS EQUITY & LIABILITIES
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO.	(1) Category		(3) Year Ended December 31, 2020		(2) 13 Monthly Average Ended December 31, 2020
1	Capitalization				
2	Common Stock	$	2,442,426	$	2,442,426
3	Preferred Stock		188,700		188,700
4	Premium On Capital Stock		1,005,875		1,005,875
5	Miscellaneous Paid-In Capital		58,778,170		54,316,632
6	Capital Stock Expense		(94,845)		(94,845)
7	Retained Earnings		44,220,302		42,753,752
8	Stockholders Equity		106,540,628		100,612,539
	Long Term Debt				
9	Bonds and Notes		106,500,000		91,153,846
10	Total		106,500,000		91,153,846
11	Current and Accrued Liabilities				
12	Accounts Payable		18,174,447		16,003,803
13	Notes Payable to Associated Co.		8,176,368		18,007,791
14	A/P to Associated Co's		10,603,841		9,316,047
15	Customer Deposits		371,830		475,508
16	Taxes Accrued		113,873		2,475,826
17	Interest Accrued		1,019,683		999,624
18	Dividends Declared		1,715,529		1,694,389
19	Tax Collections Payable		16,638		353
20	Other Accrued Liabilities		3,017,271		2,357,685
21	Total		43,209,480		51,331,026
22	Deferred Credits				
23	Customer Advances For Construction		554,217		496,613
24	Other Deferred Credits		65,121,369		46,138,857
25	Other Regulatory Liabilities		16,601,346		16,601,346
26	Deferred Income Taxes		26,410,580		27,193,774
27	Total		108,687,512		90,430,590
28	Total Stockholders Equity & Liabilities	$	364,937,619	$	333,528,001

UNITIL ENERGY SYSTEMS, INC
SCHEDULE 2B - MATERIALS & SUPPLIES
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO.	(1) DESCRIPTION	(2) DECEMBER 31 2019	(3) MARCH 31 2020	(4) JUNE 30 2020	(5) SEPTEMBER 30 2020	(6) DECEMBER 31 2020	(7) 5 QUARTER AVERAGE
1	Material and Supplies	$ 1,174,870	$ 1,262,158	$ 1,389,123	$ 1,192,748	$ 1,206,272	$ 1,245,034
2	Stores	189,428	259,182	177,187	39,287	201,952	173,407
3	Clearing Accounts	648,177	1,405,667	670,379	(449,234)	624,028	579,803
4	Total M&S Inventories	$ 2,012,476	$ 2,927,007	$ 2,236,689	$ 782,802	$ 2,032,252	$ 1,998,245

UNITIL ENERGY SYSTEMS, INC
SCHEDULE 2 ATTACHMENT 1 - 13 MONTHLY BALANCE SHEETS ENDED DECEMBER 31, 2020
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO.	Account Description	2019 December	2020 January	2020 February	2020 March	2020 April	2020 May	2020 June	2020 July	2020 August	2020 September	2020 October	2020 November	2020 December
	Electric Plant													
1	In Service	$ 363,441,699	$ 364,147,769	$ 365,604,134	$ 370,130,648	$ 369,931,960	$ 370,346,410	$ 373,019,393	$ 374,246,363	$ 375,016,916	$ 376,550,970	$ 377,091,191	$ 380,900,640	$ 408,325,135
2	Construction Work in Progress	15,945,622	16,941,969	18,460,311	19,594,435	22,482,674	25,124,672	27,117,626	30,559,386	32,887,601	34,270,792	34,489,173	30,045,407	5,132,123
3	Less: Reserve for Depreciation	(131,447,315)	(132,328,294)	(133,289,083)	(134,081,053)	(135,137,976)	(136,152,441)	(137,117,184)	(138,133,912)	(139,149,262)	(140,015,203)	(139,601,311)	(137,588,345)	(138,059,087)
4	Total Electric Plant	247,940,006	248,761,444	250,775,362	255,644,029	257,276,658	259,318,641	263,019,835	266,671,838	268,755,255	270,806,560	271,979,053	273,357,701	275,398,170
	Other Property													
5	Total Other Net Property	50,606	50,606	50,606	50,606	50,606	50,606	50,606	50,606	50,606	50,606	50,606	50,606	50,606
6	Total Other & Non Operating Plant	50,606	50,606	50,606	50,606	50,606	50,606	50,606	50,606	50,606	50,606	50,606	50,606	50,606
	Current Assets													
7	Cash	92,043	(504,693)	231,647	433,371	(203,311)	(208,265)	55,253	(291,816)	(384,444)	373,491	(237,916)	(569,162)	363,677
8	Other Special Deposits (ISO Deposit)	1,450,588	1,194,368	1,846,349	1,987,123	1,736,487	1,036,315	911,863	1,548,024	2,836,539	4,217,136	5,174,179	3,657,052	2,243,895
9	Working Funds	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,028	3,000
10	Accounts Receivable	16,168,346	17,377,436	18,132,518	18,718,043	16,538,765	16,883,581	17,803,156	18,679,227	20,895,287	20,335,819	16,986,765	16,629,661	18,946,030
11	Accounts Receivable - Other	325,887	327,865	333,890	335,840	314,415	286,109	284,060	247,137	247,939	248,190	250,244	267,949	302,295
12	Uncollectible Accounts	(161,878)	(50,798)	(145,225)	(163,378)	(163,378)	(163,378)	(163,650)	(197,550)	(197,550)	(197,550)	(219,050)	(471,869)	(556,372)
13	Accts Receivable - Assoc. Companies	4,575,451	-	771	4,872,825	-	5,000,000	5,215,127	11,349	68,760	4,604,866	-	-	6,113,320
14	Material and Supplies	1,174,870	1,218,845	1,285,070	1,262,158	1,350,823	1,408,353	1,389,123	1,221,737	1,267,982	1,192,748	1,272,785	1,290,829	1,206,272
15	Stores Expense Undistributed	189,428	200,591	207,283	259,182	208,975	185,423	177,187	70,335	71,223	39,287	63,978	106,375	201,952
16	Prepayments	6,868,916	6,515,585	6,057,441	5,708,805	5,303,721	4,760,398	6,270,776	5,794,044	4,987,256	5,806,779	5,207,644	4,578,617	6,012,559
17	Accrued Revenue	13,258,847	8,684,739	8,231,316	11,418,500	6,486,580	7,003,070	10,787,678	7,533,741	7,956,504	11,397,916	6,352,472	7,195,595	12,242,701
18	Miscellaneous Current Assets	67,464	67,464	67,464	112,017	112,017	112,017	173,995	173,995	173,995	163,359	163,359	163,359	146,491
19	Total	44,012,963	35,034,402	36,251,525	44,947,487	31,688,092	36,306,623	42,907,567	34,793,224	37,926,491	48,185,041	35,017,459	32,851,434	47,225,819
	Deferred Charges													
20	Unamortized Debt Expense	1,180,809	1,169,151	1,157,493	1,150,160	1,142,828	1,135,495	1,128,162	1,120,830	1,113,497	1,260,096	1,258,541	1,262,856	1,254,801
21	Other - Deferred Debits	41,700,297	29,668,545	29,455,587	38,281,208	26,671,371	26,339,393	37,109,242	24,423,107	24,146,909	35,654,130	24,055,468	24,505,255	41,008,223
22	Total Deferred Charges	42,881,106	30,837,696	30,613,080	39,431,368	27,814,199	27,474,888	38,237,405	25,543,937	25,260,407	36,914,225	25,314,010	25,768,112	42,263,024
23	Total Assets & Deferred Charges	$ 334,884,681	$ 314,684,149	$ 317,690,572	$ 340,073,491	$ 316,829,556	$ 323,150,758	$ 344,215,413	$ 327,059,605	$ 331,992,759	$ 355,956,433	$ 332,361,129	$ 332,027,853	$ 364,937,619
	Capitalization													
24	Common Stock	$ 2,442,426	$ 2,442,426	$ 2,442,426	$ 2,442,426	$ 2,442,426	$ 2,442,426	$ 2,442,426	$ 2,442,426	$ 2,442,426	$ 2,442,426	$ 2,442,426	$ 2,442,426	$ 2,442,426
25	Preferred Stock	188,700	188,700	188,700	188,700	188,700	188,700	188,700	188,700	188,700	188,700	188,700	188,700	188,700
26	Premium On Capital Stock	1,005,875	1,005,875	1,005,875	1,005,875	1,005,875	1,005,875	1,005,875	1,005,875	1,005,875	1,005,875	1,005,875	1,005,875	1,005,875
27	Miscellaneous Paid-In Capital	51,028,170	51,028,170	51,028,170	51,028,170	51,028,170	56,028,170	56,028,170	56,028,170	56,028,170	56,028,170	56,028,170	56,028,170	58,778,170
28	Capital Stock Expense	(94,845)	(94,845)	(94,845)	(94,845)	(94,845)	(94,845)	(94,845)	(94,845)	(94,845)	(94,845)	(94,845)	(94,845)	(94,845)
29	Retained Earnings	42,949,034	41,490,039	41,910,232	42,237,826	40,995,803	41,585,881	42,838,727	42,774,966	43,895,125	44,310,367	43,000,585	43,589,890	44,220,302
30	Stockholders Equity	97,519,360	96,060,364	96,480,557	96,808,152	95,566,129	101,156,206	102,409,053	102,345,292	103,465,451	103,880,692	102,570,911	103,160,216	106,540,628
	Long Term Debt													
31	Bonds and Notes	87,500,000	87,500,000	87,500,000	82,500,000	82,500,000	82,500,000	82,500,000	82,500,000	82,500,000	108,000,000	106,500,000	106,500,000	106,500,000
	Total	87,500,000	87,500,000	87,500,000	82,500,000	82,500,000	82,500,000	82,500,000	82,500,000	82,500,000	108,000,000	106,500,000	106,500,000	106,500,000
	Current and Accrued Liabilities													
32	Accounts Payable	19,800,943	16,704,792	16,443,048	16,311,132	13,322,830	14,680,262	15,569,179	16,229,239	15,889,068	16,440,485	13,920,029	14,563,988	18,174,447
33	Notes Payable to Associated Co.	13,065,032	15,981,465	18,329,433	25,006,584	26,439,328	26,575,577	23,423,291	26,686,489	29,757,846	4,767,278	8,896,119	6,996,466	8,176,368
34	A/P to Associated Co's	9,541,173	9,376,630	9,385,283	9,698,509	9,259,991	8,818,583	9,023,272	8,545,817	8,763,860	9,369,379	8,869,370	9,852,898	10,603,841
35	Customer Deposits	593,573	560,488	552,883	545,176	522,785	477,319	470,020	457,857	439,116	423,792	387,725	379,042	371,830
36	Taxes Accrued	1,999,449	2,783,700	3,216,394	3,448,681	4,030,970	1,827,005	2,237,525	2,865,236	3,182,186	2,583,215	2,778,452	1,119,055	113,873
37	Interest Accrued	887,326	1,014,451	1,457,109	965,980	1,191,669	677,252	783,551	906,656	1,329,859	980,803	964,001	816,777	1,019,683
38	Dividends Declared	1,452,037	1,713,642	1,714,585	1,715,529	1,713,642	1,714,585	1,715,529	1,713,642	1,714,585	1,715,529	1,713,642	1,714,585	1,715,529
39	Tax Collections Payable	5,727	-	-	-	-	-	-	-	-	(17,778)	-	-	16,638
40	Other Accrued Liabilities	3,296,632	1,054,997	862,422	4,807,618	940,002	897,477	5,357,355	892,199	902,301	6,794,960	942,855	883,815	3,017,271
41	Total	50,641,891	49,190,164	51,961,157	62,499,209	57,421,215	55,668,061	58,579,721	58,297,135	61,978,822	43,057,663	38,472,193	36,326,627	43,209,480
	Deferred Credits													
42	Customer Advances For Construction	525,416	470,497	455,739	444,982	444,982	482,155	476,559	500,380	514,435	489,144	543,255	554,217	554,217
43	Other Deferred Credits	59,484,811	36,802,450	36,911,297	59,586,508	37,032,478	37,044,810	59,968,452	37,069,475	37,081,808	59,449,399	37,106,473	37,145,807	65,121,369
44	Other Regulatory Liabilities	16,601,346	16,601,346	16,601,346	16,601,346	16,601,346	16,601,346	16,601,346	16,601,346	16,601,346	16,601,346	16,601,346	16,601,346	16,601,346
45	Deferred Income Taxes	22,611,857	28,059,328	27,780,475	21,633,294	27,263,406	29,698,180	23,680,283	29,745,976	29,850,897	24,478,187	30,566,951	31,739,641	26,410,580
46	Total	99,223,430	81,933,621	81,748,858	98,266,130	81,342,212	83,826,491	100,726,640	83,917,177	84,048,486	101,018,077	84,818,025	86,041,011	108,687,512
47	Total Stockholders Equity & Liabilities	$ 334,884,681	$ 314,684,149	$ 317,690,572	$ 340,073,491	$ 316,829,556	$ 323,150,758	$ 344,215,413	$ 327,059,605	$ 331,992,759	$ 355,956,433	$ 332,361,129	$ 332,027,853	$ 364,937,619

UNITIL ENERGY SYSTEMS, INC
SCHEDULE 3 - RATE BASE
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO.	(1) DESCRIPTION	(2) REFERENCE	(3) TEST YEAR AVERAGE[(1)]	(4) 5 QUARTER AVERAGE	(6) RATE BASE AT DECEMBER 31, 2020
1	Utility Plant In Service	Schedule RevReq-4-1	$ 385,883,446	$ 378,293,580	$ 408,325,193
2	Less: Reserve for Depreciation	Schedule RevReq-4-1	134,753,201	136,143,968	138,059,087
3	Net Utility Plant		251,130,244	242,149,612	270,266,106
4	Add: M&S Inventories	Schedule RevReq-4-1	$ 2,022,364	$ 1,998,245	$ 2,032,252
5	Cash Working Capital [(2)]	Schedule RevReq-4-2	2,383,150	2,383,150	2,383,150
6	Prepayments	Schedule RevReq-4-1	4,840,442	4,956,633	4,508,744
7	Sub-Total		9,245,956	9,338,028	8,924,147
8	Less: Net Deferred Income Taxes	Schedule RevReq-4-1	$ 36,365,292	$ 36,267,391	$ 38,338,666
9	Less: Excess Deferred Income Taxes	Schedule RevReq-4-1	16,601,346	16,601,346	16,601,346
10	Plus: Deferred Income Taxes Debit	Schedule RevReq-4-1	146,198	134,890	150,098
11	Less: Customers Deposits	Schedule RevReq-4-1	482,702	480,878	371,830
12	Less: Customer Advances	Schedule RevReq-4-1	539,816	498,063	554,217
13	Rate Base		$ 206,533,242	$ 197,774,851	$ 223,474,292
14	Net Operating Income Applicable To Rate Base		$ 11,613,315	$ 11,613,315	$ 11,613,315
15	Rate of Return		5.62%	5.87%	5.20%

Notes
(1) Two Point Average
(2) Computed Working Capital Based on Test Year O&M Expenses

UNITIL ENERGY SYSTEMS, INC
SCHEDULE 3A - WORKING CAPITAL
12 MONTHS ENDED DECEMBER 31, 2020

	(1)	(2)	(3)	(4)	(5)
LINE NO.	DESCRIPTION	REFERENCE	TEST YEAR ACTUAL	PROFORMA ADJUSTMENTS	TEST YEAR AS PROFORMED
1	O&M Expense	Schedule RevReq-2	22,222,234	2,061,610	24,283,845
2	Taxes and Interest Expense	Schedule RevReq-2	4,889,822	8,941,277	13,831,098
3	Total		$ 27,112,056	$ 11,002,887	$ 38,114,943
4	Cash Working Capital Requirement:				
5	Other O&M Expense Days Lag [(1)] / 366	32 days	8.79%	8.79%	8.79%
6	Total Cash Working Capital	Line 5 X Line 3	$ 2,383,150	$ 967,154	$ 3,350,303

Notes
(1) Refer to Lead-Lag Study in Direct Testimony of Daniel Hurstak

UNITIL ENERGY SYSTEMS, INC
SCHEDULE 3 ATTACHMENT - PRO FORMA ADJUSTMENTS TO RATE BASE
12 MONTHS ENDED DECEMBER 31, 2020

	(1)	(2)	(3)	(4)
LINE NO.	DESCRIPTION	RATE BASE AT DECEMBER 31, 2020	PRO FORMA ADJUSTMENTS	PRO FORMA RATE BASE AT DECEMBER 31, 2020
1	Utility Plant In Service	$ 408,325,193	$ (411,070)	$ 407,914,123
2	Less: Reserve for Depreciation	138,059,087	-	138,059,087
3	Net Utility Plant	270,266,106	(411,070)	269,855,036
4	Add: M&S Inventories	$ 2,032,252	$ -	$ 2,032,252
5	Cash Working Capital (1)	2,383,150	967,154	3,350,304
6	Prepayments	4,508,744	-	4,508,744
7	Sub-Total	8,924,147	967,154	9,891,301
8	Less: Net Deferred Income Taxes	$ 38,338,666	$ (71,351)	$ 38,267,315
9	Less: Excess Deferred Income Taxes	16,601,346	(1,928,356)	14,672,991
10	Plus: Deferred Income Taxes Debit	150,098	-	150,098
11	Less: Customers Deposits	371,830	-	371,830
12	Less: Customer Advances	554,217	-	554,217
13	Rate Base	$ 223,474,292	$ 2,555,790	$ 226,030,082
14	Net Operating Income Applicable To Rate Base	$ 11,613,315		$ 9,066,677
15	Rate of Return	5.20%		4.01%

Notes
(1) Computed Working Capital Based on Test Year O&M Expenses

[THIS PAGE INTENTIONALLY LEFT BLANK]

UNITIL ENERGY SYSTEMS, INC.
DOCKET DE 21-030
REVENUE REQUIREMENT SCHEDULES

UNITIL ENERGY SYSTEMS, INC.
REVENUE REQUIREMENT TABLE OF CONTENTS
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-TOC

UNITIL ENERGY SYSTEMS, INC.
COMPUTATION OF REVENUE DEFICIENCY AND REVENUE REQUIREMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-1
Table of Contents

LINE NO.	(1) DESCRIPTION	(2) REFERENCE	(3) AMOUNT
1	Rate Base	Schedule RevReq-4	$ 226,030,082
2	Rate Of Return	Schedule RevReq-5	7.88%
3	Income Required	Line 1 * Line 2	17,811,170
4	Adjusted Net Operating Income	Schedule RevReq-2	9,066,677
5	Deficiency	Line 3 - Line 4	8,744,493
6	Income Tax Effect	Line 7 - Line 5	3,247,900
7	Revenue Deficiency	1.3714 (Schedule RevReq-1-1) * Line 5	$ 11,992,392

UNITIL ENERGY SYSTEMS, INC.
COMPUTATION OF GROSS-UP FACTOR FOR REVENUE REQUIREMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-1-1
Table of Contents

LINE NO.	(1) DESCRIPTION	(2) RATE	(3) AMOUNT
1	Federal Income Tax Rate	21.00%	0.2100
2	State Income Tax Rate	7.70%	0.0770
3	Federal Benefit of State Income Tax	-(Line 1 * Line 2)	(0.0162)
4	Effective Tax Rate	(Line 1 + Line 2 + Line 3)	0.2708
5	Gross-Up Factor	(1 / 1 - Line 4)	1.3714

UNITIL ENERGY SYSTEMS, INC.
OPERATING INCOME STATEMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-2
Page 1 of 2
Table of Contents

LINE NO.	(1) DESCRIPTION	(2) TEST YEAR 12 MONTHS ENDED 12/31/2020	(3) TEST YEAR FLOW-THROUGH	(4) TEST YEAR DISTRIBUTION	(5) PROFORMA ADJUSTMENTS	(6) TEST YEAR DISTRIBUTION AS PROFORMED	(7) CALENDAR YEAR 2019 (1)	(8) CALENDAR YEAR 2018 (1)
1	Distribution Revenue	$ 58,337,364	$ -	$ 58,337,364	$ (280,812)	$ 58,056,553	$ 57,749,747	$ 57,757,766
2	Flow-Through Revenue	98,489,216	98,489,216	-	-	-	101,655,415	97,267,289
3	Electric Service Revenue	156,826,580	98,489,216	58,337,364	(280,812)	58,056,553	159,405,162	155,025,055
4	Other Operating Revenue	2,096,875	1,078,347	1,018,528	493,945	1,512,473	2,426,664	2,623,127
5	Total Operating Revenues	158,923,455	99,567,563	59,355,892	213,133	59,569,025	161,831,826	157,648,182
6	Operating Expenses:							
7	Purchased Power	53,020,521	52,736,269	284,252	-	284,252	65,385,884	61,038,767
8	Transmission	35,468,734	35,400,175	68,559	-	68,559	28,308,204	29,608,490
9	Distribution	9,476,199	-	9,476,199	2,113,975	11,590,175	9,195,883	9,199,438
10	Customer Accounting	4,286,916	321,671	3,965,244	449,940	4,415,184	4,655,167	4,633,933
11	Customer Service	7,326,955	7,298,180	28,775	-	28,775	5,450,371	3,773,461
12	Administrative & General	9,750,830	825,374	8,925,457	1,006,161	9,931,618	10,867,236	10,763,947
13	Depreciation	12,680,791	-	12,680,791	118,963	12,799,754	11,905,213	11,419,121
14	Amortizations	3,262,428	1,059,270	2,203,158	(761,204)	1,441,954	3,378,749	3,484,160
15	Taxes Other Than Income	7,166,678	-	7,166,678	905,507	8,072,185	6,435,130	6,519,710
16	Federal Income Tax	(1,180,388)	-	(1,180,388)	3,523,246	2,342,858	4,672,111	(173,832)
17	State Income Tax	(1,096,468)	-	(1,096,468)	1,264,624	168,156	1,707,349	(927)
18	Deferred Federal & State Income Taxes	5,203,294	-	5,203,294	(5,861,441)	(658,148)	(3,692,668)	3,207,039
19	Interest On Customers Deposits	17,026	-	17,026	-	17,026	31,594	32,204
20	Total Operating Expenses	145,383,515	97,640,939	47,742,577	2,759,771	50,502,348	148,300,222	143,505,511
21	Net Operating Income	$ 13,539,940	$ 1,926,625	$ 11,613,315	$ (2,546,638)	$ 9,066,677	$ 13,531,604	$ 14,142,671

Notes
(1) Calendar Years 2019 and 2018 Represents Total Company (i.e., Flow-Through and Distribution).

UNITIL ENERGY SYSTEMS, INC.
PRO FORMA DISTRIBUTION OPERATING INCOME STATEMENT
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO.	(1) DESCRIPTION	(2) TEST YEAR DISTRIBUTION	(3) PROFORMA ADJUSTMENTS	(4) TEST YEAR DISTRIBUTION AS PROFORMED	(5) PROOF REVENUE REQUIREMENT	(6) PROOF PRO FORMA RATE RELIEF
1	Distribution Revenue	$ 58,337,364	$ (280,812)	$ 58,056,553	$ 11,992,392	$ 70,048,945
2	Flow-Through Revenue	-	-	-	-	-
3	Electric Service Revenue	58,337,364	(280,812)	58,056,553	11,992,392	70,048,945
4	Other Operating Revenue	1,018,528	493,945	1,512,473	-	1,512,473
5	Total Operating Revenues	59,355,892	213,133	59,569,025	11,992,392	71,561,417
6	Operating Expenses:					
7	Purchased Power	284,252	-	284,252	-	284,252
8	Transmission	68,559	-	68,559	-	68,559
9	Distribution	9,476,199	2,113,975	11,590,175	-	11,590,175
10	Customer Accounting	3,965,244	449,940	4,415,184	-	4,415,184
11	Customer Service	28,775	-	28,775	-	28,775
12	Administrative & General	8,925,457	1,006,161	9,931,618	-	9,931,618
13	Depreciation	12,680,791	118,963	12,799,754	-	12,799,754
14	Amortizations	2,203,158	(761,204)	1,441,954	-	1,441,954
15	Taxes Other Than Income	7,166,678	905,507	8,072,185	-	8,072,185
16	Federal Income Tax	(1,180,388)	3,523,246	2,342,858	2,324,485	4,667,344
17	State Income Tax	(1,096,468)	1,264,624	168,156	923,414	1,091,570
18	Deferred Federal & State Income Taxes	5,203,294	(5,861,441)	(658,148)	-	(658,148)
19	Interest On Customers Deposits	17,026	-	17,026	-	17,026
20	Total Operating Expenses	47,742,577	2,759,771	50,502,348	3,247,900	53,750,247
21	Net Operating Income	$ 11,613,315	$ (2,546,638)	$ 9,066,677	$ 8,744,493	$ 17,811,170

UNITIL ENERGY SYSTEMS, INC.
SUMMARY OF ADJUSTMENTS
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3
Table of Contents

LINE NO.	(1) DESCRIPTION	(2) CLASSIFICATION	(3) SCHEDULE NO.	(4) AMOUNT
1	Revenue Adjustments			
2	Non-Distribution Bad Debt	Dist Rev	Schedule RevReq-3-1	(143,623)
3	Unbilled Revenue Adjustment	Dist Rev	Schedule RevReq-3-1	(137,189)
4	New DOC Rent Revenue	Oth Rev	Schedule RevReq-3-1	313,007
5	Late Fee Adjustment	Oth Rev	Schedule RevReq-3-1	180,938
6	Total Revenue Adjustments			$ 213,133
7	Operating & Maintenance Expense Adjustments			
8	Payroll	Dist	Schedule RevReq-3-2	$ 709,516
9	VMP Expense	Dist	Schedule RevReq-3-3	1,406,427
10	Medical & Dental Insurances	A&G	Schedule RevReq-3-4	483,155
11	Pension	A&G	Schedule RevReq-3-5	62,288
12	PBOP	A&G	Schedule RevReq-3-5	(41,636)
13	SERP	A&G	Schedule RevReq-3-5	85,989
14	401K	A&G	Schedule RevReq-3-5	41,844
15	Deferred Comp Expense	A&G	Schedule RevReq-3-5	64,957
16	Property & Liability Insurances	A&G	Schedule RevReq-3-6	72,468
17	DOC Expense Adjustment	Dist	Schedule RevReq-3-7	(1,968)
18	NHPUC Regulatory Assessment	A&G	Schedule RevReq-3-8	159,383
19	Dues & Subscriptions	A&G	Schedule RevReq-3-9	(14,473)
20	Pandemic Costs	A&G	Schedule RevReq-3-10	(39,857)
21	Claims & Litigation Adjustment	A&G	Schedule RevReq-3-11	44,072
22	Severance Expense	A&G	Schedule RevReq-3-12	(40,395)
23	Distribution Bad Debt	Cust Acct	Schedule RevReq-3-13	134,563
24	Non-Distribution Bad Debt	Cust Acct	Schedule RevReq-3-1	(143,623)
25	Arrearage Management Program (AMP) Implementation Cost	Cust Acct	Schedule RevReq-3-14	459,000
26	Inflation Allowance	A&G	Schedule RevReq-3-15	128,368
27	Total Operating & Maintenance Expense Adjustments			$ 3,570,077
28	Depreciation & Amortization Expense Adjustments			
29	Depreciation Annualization	Depr	Schedule RevReq-3-16 P1	$ 908,712
30	Proposed Depreciation Rates	Depr	Schedule RevReq-3-16 P2	(789,749)
31	Software Amortization	Amort	Schedule RevReq-3-17	238,591
32	Excess ADIT Flowback	Amort	Schedule RevReq-3-18	(999,795)
33	Total Depreciation & Amortization Expense Adjustments			$ (642,241)
34	Taxes Other Than Income Adjustments			
35	Property Taxes	Taxes Other	Schedule RevReq-3-19	$ 744,985
36	Payroll Taxes - Wage Increases	Taxes Other	Schedule RevReq-3-20 P1	54,278
37	Payroll Taxes - Employee Retention Credit	Taxes Other	Schedule RevReq-3-20 P2	106,244
38	Total Taxes Other Than Income Adjustments			$ 905,507
39	Income Taxes Adjustments			
40	Federal Income Tax	FIT	Schedule RevReq-3-21 P1	$ (770,033)
41	State Income Tax	SIT	Schedule RevReq-3-21 P1	(305,900)
42	Prior Year Federal Income Tax	FIT	Schedule RevReq-3-21 P4	4,293,279
43	Prior Year State Income Tax	SIT	Schedule RevReq-3-21 P4	1,570,523
44	Prior Year Deferred Federal Income Tax	DIT	Schedule RevReq-3-21 P4	(4,290,918)
45	Prior Year Deferred State Income Tax	DIT	Schedule RevReq-3-21 P4	(1,570,523)
46	Total Income Taxes Adjustments			$ (1,073,571)
47	Rate Base Adjustments			
48	Cash Working Capital Adjustment	CWC	Schedule RevReq-4-2	$ 967,154
49	Kensington Distribution Operating Center Adj. - Net Book Value	Plant	Schedule RevReq-4-3	(988,214)
50	Kensington Distribution Operating Center Adj. - ADIT	RB DIT	Schedule RevReq-4-3	(71,351)
51	Exeter Distribution Operating Center Adj. - Net Book Value	Plant	Schedule RevReq-4-4	577,144
52	Excess Accumulated Income Tax Adj. (Storm)	EDIT	Schedule RevReq-4-5	(2,644,590)
53	Accumulated Deferred Income Tax Adj. (Storm)	EDIT	Schedule RevReq-4-5	716,234
54	Total Rate Base Adjustments			$ 2,555,790

UNITIL ENERGY SYSTEMS, INC.
REVENUE ADJUSTMENTS
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-1
Table of Contents

	(1)		(2)
LINE NO.	DESCRIPTION		AMOUNT
1	Non Distribution Bad Debt Adjustment (Revenue & Expense)		
2	Remove: Accrued Revenue - Non Dist Bad Debt	$	(143,623)
3	Remove: Provision For Doubtful Accts - Non-Dist	$	(143,623)
4	Unbilled Revenue Adjustment		
5	Remove Unbilled Revenue	$	(137,189)
6	Rent Revenue Adjustment		
7	Annual DOC Rental Revenue Received from USC	$	313,007
8	Late Payment Revenue Adjustment [(1)]		
9	Late Payment Revenue Adjustment	$	180,938

Notes
(1) Refer to Workpaper 1.1

UNITIL ENERGY SYSTEMS, INC.
PAYROLL ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-2
Page 1 of 2
Table of Contents

LINE NO.	(1) DESCRIPTION	(2) UES NONUNION	(3) UES UNION	(4) UES SUBTOTAL	(5) FROM USC	(6) TOTAL
1	Test Year Payroll, Adjusted for Target Incentive Compensation	$ 1,405,138	$ 4,793,090	$ 6,198,228	$ 8,630,554	$ 14,828,782
2	2020 Rate Increase, Annualized (1)	-	57,518	57,518	-	57,518
3	Payroll Annualized for 2020 Union Wage Increase	1,405,138	4,850,608	6,255,746	8,630,554	14,886,300
4	2021 Salary & Wage Increase (2)	51,288	145,518	196,806	379,744	576,550
5	Payroll Proformed for 2020 and 2021 Wage Increases	1,456,426	4,996,126	6,452,552	9,010,298	15,462,850
6	2022 Salary & Wage Increase (3)	53,160	149,884	203,043	396,453	599,496
7	Payroll Proformed for 2020, 2021 and 2022 Wage Increases	1,509,585	5,146,010	6,655,595	9,406,751	16,062,346
8	Less Amounts Chargeable to Capital(4)	969,908	3,306,311	4,276,219	2,676,221	6,952,440
9	O&M Payroll Proformed	539,677	1,839,699	2,379,376	6,730,530	9,109,907
10	Less: Test Year O&M Payroll(5)			2,225,229	6,175,162	8,400,391
11	Increase in O&M Payroll due to Annual Salary and Wage Increases			154,147	555,368	709,516
12	Incentive Compensation Target Adjustment(6)			$ -	-	-
13	Net Adjustment to O&M Payroll / Compensation			154,147	555,368	709,516

Notes
(1) UES Union increase of 3.0% effective June 1, 2020
(2) UES Non-union increase of 3.65% effective January 1, 2021, Union increase of 3.0% effective June 1, 2021 and USC increase of 4.40% effective January 1, 2021
(3) UES Non-union increase of 3.65% effective January 1, 2022, Union increase of 3.0% effective June 1, 2022 and USC increase of 4.40% effective January 1, 2022
(4) Test Year Payroll Capitalization Rates:

UES	64.25%
USC	28.45%

(5) Refer to Workpaper 2.2 and Schedule RevReq-3-2, page 2.
(6) Refer to Workpaper 2.4

UNITIL ENERGY SYSTEMS, INC.
UNITIL SERVICE CORP PAYROLL ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO.	(1) DESCRIPTION	(2) TOTAL
1	Test Year USC Labor Charges to Unitil Energy [1]	$ 8,630,554
2	2021 Salary & Wage Increase %[2]	4.40%
3	Payroll Increase	379,744
4	Proforma Payroll for 2019 Increase	9,010,298
5	2022 Salary & Wage Increase %[2]	4.40%
6	Payroll Increase	396,453
7	Proforma Payroll for 2019 and 2020 Increase	9,406,751
8	Payroll Capitalization Ratio for 2021 and 2022 Increase	28.45%
9	Proforma Payroll Capitalization	2,676,221
10	Proforma Amount to O&M Expense	6,730,530
11	Test Year O&M Payroll Amount of USC Charge	6,175,162
12	O&M Payroll Increase	$ 555,368

Notes
(1) Includes Incentive Compensation at Target of $938,339
(2) Average Increase of 4.40% Effective January 1, 2021 and Average Increase of 4.40% Effective January 1, 2022

UNITIL ENERGY SYSTEMS, INC.
RELIABILITY ENHANCEMENT AND VEGETATION MANAGEMENT PROGRAM ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-3
Table of Contents

	(1)	(2)	(3)
LINE NO.	DESCRIPTION	2020 (1)	2021 (1)
1	Cycle Prune	$ 1,487,245	$ 1,746,507
2	Hazard Tree Mitigation	934,544	840,000
3	Forestry Reliability Work	18,168	115,360
4	Mid-Cycle Review	31,791	25,603
5	Police / Flagger	676,997	619,515
6	Core Work	176,579	154,500
7	VM Planning	-	-
8	Distribution Total	3,325,322	3,501,485
9	Sub-T	363,327	620,069
10	Substation Spraying	10,798	13,431
11	VM Staff	376,758	364,491
12	Program Total	4,076,205	4,499,476
13	Storm Resiliency Program	1,439,617	1,465,690
14	Reliability Enhancement Program	152,803	300,000
15	Deferral as of 12/31/2020	179,614	-
16	Total REP & VMP Expense	$ 5,848,239	$ 6,265,166
17	Increase in REP & VMP Expense		$ 416,927
18	Removal of Test Year Third Party Reimbursement (2)		989,500
19	Total Increase in REP & VMP Expense		$ 1,406,427

Notes
(1) Per DE 20-183 filing made on February 17, 2021
(2) To be refunded as part of the Company's External Delivery Charge (EDC)

UNITIL ENERGY SYSTEMS, INC.
MEDICAL AND DENTAL INSURANCE ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-4
Table of Contents

	(1)	(2)	(3)	(4)
LINE NO.	DESCRIPTION	TOTAL	UNITIL ENERGY SYSTEMS, INC. (1)	UNITIL SERVICE CORP. (2)
1	Proformed Medical and Dental O&M Expense	$ 995,556	$ 219,155	$ 776,401
2	Less: Test Year Medical And Dental Insurance O&M Expense	512,402	95,921	416,480
3	Proformed 2021 And 2022 O&M Increase	$ 483,155	$ 123,234	$ 359,921

Notes
(1) See Workpapers W3.1
(2) See Workpapers W3.2

Unitil Energy Systems, Inc.
PENSION, PBOP, SERP, 401(K) and Deferred Compensation Expense
12 MONTHS ENDED DECEMBER 21, 2020

Schedule RevReq-3-5
Table of Contents

	(1)	(2)	(3)	(4)
LINE NO.	DESCRIPTION	TOTAL	UNITIL ENERGY SYSTEMS, INC.	UNITIL SERVICE CORP.
1	Test Year Pension Expense, as Pro-Formed	$ 1,122,160	$ 479,438	$ 642,721
2	Test Year PBOP Expense, as Pro-Formed	849,272	579,088	270,185
3	Test Year SERP Expense, as Pro-Formed	468,678	-	468,678
4	Test Year 401K Expense, as Pro-Formed	534,997	102,860	432,136
5	Test Year Deferred Comp Expense, as Pro-Formed	77,097	-	77,097
6	Total Test Year Retirement Costs as Pro-Formed	3,052,204	1,161,386	1,890,817
7	Test Year Pension Expense	$ 1,059,872	$ 456,916	$ 602,955
8	Test Year PBOP Expense	890,909	590,644	300,265
9	Test Year SERP Expense	382,690	-	382,690
10	Test Year 401K Expense	493,152	96,674	396,479
11	Test Year Deferred Comp Expense	12,140	-	12,140
12	Total Test Year Retirement Costs	2,838,762	1,144,234	1,694,528
13	Test Year Pension Expense, Pro-Forma Adjustment (1)	62,288	22,522	39,766
14	Test Year PBOP Expense, Pro-Forma Adjustment (2)	(41,636)	(11,556)	(30,080)
15	Test Year SERP Expense, Pro-Forma Adjustment (3)	85,989	-	85,989
16	Test Year 401K Expense, Pro-Forma Adjustment (4)	41,844	6,187	35,658
17	Test Year Deferred Comp Expense, Pro-Forma Adjustment (5)	64,957	-	64,957
18	Total Test Year Pension, PBOP and 401K Expense, Pro-Forma Adjustment	$ 213,441	$ 17,152	$ 196,289

Notes
(1) Refer to Workpaper 4.1
(2) Refer to Workpaper 4.2
(3) Refer to Workpaper 4.3
(4) Refer to Workpaper 4.4
(5) Refer to Workpaper 4.6

UNITIL ENERGY SYSTEMS, INC.
PROPERTY & LIABILITY INSURANCE
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-6
Table of Contents

LINE NO.	(1) DESCRIPTION	(2) TOTAL	(3) UES (1)	(4) UNITIL SERVICE CORP. (2)
1	Proformed Property & Liability Insurances O&M Expense	$ 369,896	$ 328,517	$ 41,379
2	Less: Test Year Property & Liability Insurances O&M Expense	297,428	273,026	24,402
3	Proformed 2021 And 2022 O&M Increase	$ 72,468	$ 55,491	$ 16,977

Notes
(1) See Workpaper W5.1
(2) See Workpaper W5.2

UNITIL ENERGY SYSTEMS, INC.
DISTRIBUTION OPERATION CENTER EXPENSE ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-7
Table of Contents

	(1)		(2)
LINE NO.	DESCRIPTION		AMOUNT
1	New Exeter DOC Operating Expense [1]	$	119,250
2	Test Year DOC Operating Expense		121,218
3	Change in DOC Operating Expense		(1,968)

Notes
(1) Amount reflects 2021 budget and will be updated with 2021 actuals during pendency of case

UNITIL ENERGY SYSTEMS, INC.
REGULATORY ASSESSMENT FEE ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-8
Table of Contents

	(1)	(2)
LINE NO.	**DESCRIPTION**	**AMOUNT**
1	Regulatory Assessment for Fiscal Year 2021	$ 801,884
2	Less: Supplier Portion	10,000
3	Regulatory Assessment Assigned to Base	791,884
4	Test Year Regulatory Assessment Assigned to Base	632,501
5	Regulatory Assessment Fee Adjustment	$ 159,383

UNITIL ENERGY SYSTEMS, INC.
DUES & SUBSCRIPTION ADJUSTEMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-9
Table of Contents

	(1)	(2)
LINE NO.	DESCRIPTION	AMOUNT
1	EEI Membership Dues	
2	Regular Activities of Edison Electric Institute [1]	$ 61,515
3	Industry Issues [2]	6,152
4	Restoration, Operations, and Crisis Management Program [3]	2,000
5	2021 Contribution to The Edison Foundation, which funds IEI [4]	5,000
6	Total	74,667
7	Amount allocated to UES	68%
8	Test Year UES Dues & Subscriptions	50,774
9	Adjustment to remove lobbying portion of Dues & Subscriptions	(14,473)

Notes

(1) The portion of 2021 membership dues relating to influencing legislation, which is not deductible for federal income tax purposes, is estimated to be 13%

(2) The portion of the 2021 industry issues support relating to influencing legislation is estimated to be 24%

(3) The Restoration, Operations, and Crisis Management Program is related to improvements to industry–wide responses to major outages (e.g. National Response Event); continuity of industry and business operations; and EEI's all hazards (storms, wildfires, cyber, etc.) support and coordination of the industry during times of crises. No portion of this assessment is allocable to influencing legislation

(4) The Edison Foundation is an IRC 501(c)(3) educational and charitable organization. Contributions are deductible for federal income tax purposes to the extent provided by law. Please consult your tax advisor with respect to your specific situation

UNITIL ENERGY SYSTEMS, INC.
PANDEMIC COST ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-10
Table of Contents

	(1)	(2)	
LINE NO.	DESCRIPTION	AMOUNT	
1	Pandemic Cost Adjustment - UES	$	30,250
2	Unitil Service Expense Allocated to UES		
3	Total Unitil Service Pandemic Costs	$	49,496
4	UES Apportionment		27.50%
5	Expense Apportioned to UES	$	13,611
6	Capitalization Rate		29.42%
7	UES Capitalization		4,004
8	UES Net O&M Medical Expense	$	9,607
9	Removal of Total Pandemic Costs from Test Year	$	(39,857)

UNITIL ENERGY SYSTEMS, INC.
CLAIMS & LITIGATION ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-11
Table of Contents

	(1)	(2)	
LINE NO.	**DESCRIPTION**	**AMOUNT**	
1	Claims & Litigation Adjustment [(1)]	$	44,072

Notes
(1) Test year reflects a reclass adjustment from UES to Northern Utilities - Maine Division for inadvertent expense booked in calendar year 2019

UNITIL ENERGY SYSTEMS, INC.
SEVERANCE EXPENSE ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-12
Table of Contents

	(1)	(2)
LINE NO.	DESCRIPTION	AMOUNT
1	Removal of test year severance expense	$ (40,395)

UNITIL ENERGY SYSTEMS, INC.
DISTRIBUTION BAD DEBT ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-13
Table of Contents

	(1)	(2)
LINE NO.	DESCRIPTION	AMOUNT
1	Calendar Year 2019 Write-Offs as a % of Retail Delivery Billed Revenue [1]	0.64%
2	Per Books Delivery Retail Billed Revenue - Calendar Year 2019 [1]	$ 91,933,881
3	Revenue Increase from Rate Case	11,992,392
4	2020 Total Normalized Delivery Retail Billed Revenue	$ 103,926,273
5	Uncollectible Delivery Revenue	$ 660,815
6	Less: Test Year Bad Debt Expense	$ 526,252
7	Increase in Bad Debt Expense	$ 134,563

Notes
(1) Normalized write offs and per books delivery retail billed revenue by using 2019 calendar year activity

UNITIL ENERGY SYSTEMS, INC.
ARREARAGE MANGAEMENT PROGRAM (AMP) IMPLEMENTATION ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-14
Table of Contents

	(1)	(2)
LINE NO.	DESCRIPTION	AMOUNT
1	Required AMP Full Time Employee	$ 84,000
2	Annual AMP Forgiveness [1]	375,000
3	Total AMP Implementation Costs	$ 459,000

Notes
(1) Annual over/under recovery of AMP forgiveness to be reconciled through Company's External Delivery Charge (EDC)

UNITIL ENERGY SYSTEMS, INC.
INFLATION ALLOWANCE
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-15
Page 1 of 2
Table of Contents

LINE NO.	(1) DESCRIPTION		(2) TOTAL
1	Test Year Distribution O&M Expenses	$	22,748,486
	Less Normalizing Adjustments Items:		
2	Payroll	$	8,400,391
3	Medical and Dental Insurance		512,402
4	401K Costs		493,152
5	Property & Liability Insurance		297,428
6	Regulatory Assessment Fees		632,501
7	Total Normalizing Adjustment Items	$	10,335,874
	Less Items not Subject to Inflation:		
8	Pension	$	1,059,872
9	Postemployment Benefits Other than Pensions		890,909
10	Supplemental Executive Retirement Plan		382,690
11	Deferred Comp Expense		12,140
12	Bad Debts		526,252
13	Vegetation Management Expense		4,858,739
14	Postage		298,842
15	Amortizations - USC Charge		107,733
16	Facility Leases - USC Charge		454,965
17	Total Items not Subject to Inflation	$	8,592,140
18	Residual O&M Expenses	$	3,820,472
19	Projected Inflation Rate(1)		3.36%
20	Increase in Other O&M Expense for Inflation	$	128,368

Notes
(1) Refer to Schedule RevReq-3-15, Page 2 of 2

UNITIL ENERGY SYSTEMS, INC.
INFLATION ALLOWANCE
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-15
Page 2 of 2
Table of Contents

LINE NO.	(1) DESCRIPTION	(2) INDEX[1]
	GDPIPD Index Value at the end of the Test Year:	
1	June 2020 Index-GDP	113.0
2	July 2020 Index-GDP	113.3
3	July 1, 2020 (Midpoint of Test Year) Index	113.2
	GDPIPD Index Value at date of permanent rates :	
4	March 2022 Index-GDP	116.8
5	April 2022 Index-GDP	117.1
6	April 1, 2022 (Date of Permanent Rates) Index	117.0
7	Projected Inflation Rate	3.36%

Notes
(1) Refer to Workpaper W6.1 for GDPIPD Indices

UNITIL ENERGY SYSTEMS, INC.
DEPRECIATION ANNUALIZATION
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-16
Page 1 of 2
Table of Contents

LINE NO.	(1) DESCRIPTION	(2) PLANT BALANCE 12/31/2020	(3) ADJUSTMENTS	(4) LESS NON DEPRECIABLE	(5) DEPRECIABLE PLANT	(6) LESS ITEMS CHARGED TO CLEARING ACCOUNT	(7) DEPRECIABLE PLANT CHARGED TO DEPRECIATION EXPENSE	(8) CURRENT DEPRECIATION RATES	(9) ANNUAL PROFORMED EXPENSE
1	Intangible Plant								
2	301-Organization	$ 380	$ -	$ 380	$ -	$ -	$ -	N/A	N/A
3	303-Misc Intangible Plant	21,916,840	-	21,916,840	-	-	-	N/A	N/A
4	Total Intangible Plant	21,917,220	-	21,917,220	-	-	-	N/A	N/A
5	Other Production Plant:								
6	343-Movers	56,575	-	-	56,575	-	56,575	6.67%	3,774
7	Total Other Production Plant	56,575	-	-	56,575	-	56,575	6.67%	3,774
8	Distribution Plant								
9	360-Land & Land Rights	2,677,472	-	2,677,472	-	-	-	N/A	N/A
10	361-Structures & Improvements	2,173,616	-	-	2,173,616	-	2,173,616	2.45%	53,254
11	362-Station Equipment	50,412,132	-	-	50,412,132	-	50,412,132	2.60%	1,310,715
12	364-Poles, Towers & Fixtures	75,140,861	-	-	75,140,861	-	75,140,861	3.70%	2,780,212
13	365-Overhead Conductors & Devices	92,313,723	-	-	92,313,723	-	92,313,723	3.64%	3,360,220
14	366-Underground Conduit	2,587,958	-	-	2,587,958	-	2,587,958	2.04%	52,794
15	367-Underground Conductors & Devices	23,862,963	-	-	23,862,963	-	23,862,963	2.55%	608,506
16	368.0-Line Transformers	29,259,308	-	-	29,259,308	-	29,259,308	3.00%	877,779
17	368.1-Line Transformer Installations	25,947,042	-	-	25,947,042	-	25,947,042	2.89%	749,870
18	369-Services	25,642,632	-	-	25,642,632	-	25,642,632	5.67%	1,453,937
19	370.0-Meters	11,764,062	-	-	11,764,062	-	11,764,062	5.00%	588,203
20	370.1-Meter Installations	7,165,765	-	-	7,165,765	-	7,165,765	5.00%	358,288
21	371-Installations On Customer Premises	2,404,367	-	-	2,404,367	-	2,404,367	7.56%	181,770
22	373-Street Lighting & Signal Systems	3,580,954	-	-	3,580,954	-	3,580,954	7.79%	278,956
23	Total Distribution Plant	354,932,857	-	2,677,472	352,255,384	-	352,255,384	3.59%	12,654,504
24	General Plant								
25	389-General & Misc. Structure (1)	1,363,295	(9,679)	1,353,616	-	-	-	N/A	N/A
26	390-Structures (1)	19,114,262	(482,234)	-	18,632,028	-	18,632,028	2.08%	387,546
27	391.1-Office Furniture & Equipment	1,289,877	76,307	-	1,366,184	-	1,366,184	5.83%	79,649
28	391.3-Computer Equipment	-	-	-	-	-	-	N/A	N/A
29	392-Transportation Equip	1,073,517	-	-	1,073,517	1,073,517	-	N/A	N/A
30	393-Stores Equip	90,657	4,536	-	95,192	-	95,192	3.36%	3,198
31	394-Tools, Shop & Garage Eq	2,429,892	-	-	2,429,892	-	2,429,892	3.64%	88,448
32	395-Laboratory Equipment	948,530	-	-	948,530	-	948,530	3.90%	36,993
33	397-Communication Equip	5,005,568	-	-	5,005,568	-	5,005,568	6.60%	330,367
34	398-Miscellaneous Equip	102,943	-	-	102,943	-	102,943	4.88%	5,024
35	Total General Plant	31,418,541	(411,070)	1,353,616	29,653,855	1,073,517	28,580,338	3.26%	931,225
36	Total Plant in Service	$ 408,325,192	$ (411,070)	$ 25,948,308	$ 381,965,814	$ 1,073,517	$ 380,892,297	3.57%	$ 13,589,503
37	Test Year Expense								12,680,791
38	Increase In Depreciation Expense								$ 908,712

Notes
(1) Refer to Schedule RevReq-4-3 and Schedule RevReq-4-4

UNITIL ENERGY SYSTEMS, INC.
DEPRECIATION ANNUALIZATION
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-16
Page 2 of 2
Table of Contents

LINE NO.	(1) DESCRIPTION	(2) PLANT BALANCE 12/31/2020	(3) ADJUSTMENTS	(4) LESS NON DEPRECIABLE	(5) DEPRECIABLE PLANT	(6) LESS ITEMS CHARGED TO CLEARING ACCOUNT	(7) DEPRECIABLE PLANT CHARGED TO DEPRECIATION EXPENSE	(8) PROPOSED DEPRECIATION RATES	(9) PROPOSED PROFORMED EXPENSE
1	Intangible Plant								
2	301-Organization	$ 380	$ -	$ 380	$ -	$ -	$ -	N/A	N/A
3	303-Misc Intangible Plant	21,916,840	-	21,916,840	-	-	-	N/A	N/A
4	Total Intangible Plant	21,917,220	-	21,917,220	-	-	-	N/A	N/A
5	Other Production Plant:								
6	343-Movers	56,575	-	-	56,575	-	56,575	18.66%	10,557
7	Total Other Production Plant	56,575	-	-	56,575	-	56,575	18.66%	10,557
8	Distribution Plant								
9	360-Land & Land Rights	2,677,472	-	2,677,472	-	-	-	N/A	N/A
10	361-Structures & Improvements	2,173,616	-	-	2,173,616	-	2,173,616	2.40%	52,167
11	362-Station Equipment	50,412,132	-	-	50,412,132	-	50,412,132	2.96%	1,492,199
12	364-Poles, Towers & Fixtures	75,140,861	-	-	75,140,861	-	75,140,861	3.61%	2,712,585
13	365-Overhead Conductors & Devices	92,313,723	-	-	92,313,723	-	92,313,723	3.62%	3,341,757
14	366-Underground Conduit	2,587,958	-	-	2,587,958	-	2,587,958	2.16%	55,900
15	367-Underground Conductors & Devices	23,862,963	-	-	23,862,963	-	23,862,963	2.85%	680,094
16	368.0-Line Transformers	29,259,308	-	-	29,259,308	-	29,259,308	2.46%	719,779
17	368.1-Line Transformer Installations	25,947,042	-	-	25,947,042	-	25,947,042	2.30%	596,782
18	369-Services	25,642,632	-	-	25,642,632	-	25,642,632	2.43%	623,116
19	370.0-Meters	11,764,062	-	-	11,764,062	-	11,764,062	8.76%	1,030,532
20	370.1-Meter Installations	7,165,765	-	-	7,165,765	-	7,165,765	5.51%	394,834
21	371-Installations On Customer Premises	2,404,367	-	-	2,404,367	-	2,404,367	8.03%	193,071
22	373-Street Lighting & Signal Systems	3,580,954	-	-	3,580,954	-	3,580,954	1.49%	53,356
23	Total Distribution Plant	354,932,857	-	2,677,472	352,255,384	-	352,255,384	3.39%	11,946,172
24	General Plant								
25	389-General & Misc. Structure [(1)]	1,363,295	(9,679)	1,353,616	-	-	-	N/A	N/A
26	390-Structures [(1)]	19,114,262	(482,234)	-	18,632,028	-	18,632,028	1.85%	344,693
27	391.1-Office Furniture & Equipment	1,289,877	76,307	-	1,366,184	-	1,366,184	5.95%	81,224
28	391.3-Computer Equipment	-	-	-	-	-	-	N/A	N/A
29	392-Transportation Equip	1,073,517	-	-	1,073,517	1,073,517	-	N/A	N/A
30	393-Stores Equip	90,657	4,536	-	95,192	-	95,192	1.75%	1,670
31	394-Tools, Shop & Garage Eq	2,429,892	-	-	2,429,892	-	2,429,892	3.40%	82,572
32	395-Laboratory Equipment	948,530	-	-	948,530	-	948,530	2.97%	28,137
33	397-Communication Equip	5,005,568	-	-	5,005,568	-	5,005,568	4.34%	217,198
34	398-Miscellaneous Equip	102,943	-	-	102,943	-	102,943	0.93%	962
35	Total General Plant	31,418,541	(411,070)	1,353,616	29,653,855	1,073,517	28,580,338	2.65%	756,456
36	Total Plant in Service	$ 408,325,192	$ (411,070)	$ 25,948,308	$ 381,965,814	$ 1,073,517	$ 380,892,297	3.36%	$ 12,713,185
37	Reserve Adjustment For Amortization [(2)]								
38	390-Structures								(173)
39	391.1-Office Furniture & Equipment								66,592
40	391.3-Computer Equipment								(869)
41	393-Stores Equip								908
42	394-Tools, Shop & Garage Eq								22,424
43	395-Laboratory Equipment								58
44	397-Communication Equip								(1,754)
45	398-Miscellaneous Equip								(617)
46	Total Reserve Adjustment for Amortization								86,569
47	Total Pro Forma Depreciation Expense (Line 36 + Line 46)								12,799,754
48	Annualized Test Year Expense [(3)]								13,589,503
49	Increase In Depreciation Expense								$ (789,749)

Notes
(1) Refer to Schedule RevReq-4-3 and Schedule RevReq-4-4
(2) Refer to testimony and schedules of Mr. Allis
(3) Refer to Schedule RevReq-3-16, Page 1 of 2, Line 34

UNITIL ENERGY SYSTEMS, INC.
AMORTIZATION ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-17
Table of Contents

LINE NO.	(1) DESCRIPTION		(2) TOTAL
1	Unitil Energy Systems Rate Year Software Amortization [1]	$	1,585,103
2	USC Allocated Rate Year Software Amortization[2]		162,109
3	Total Rate Year Software Amortization		1,747,212
4	Unitil Energy Systems Test Year Software Amortization[3]	$	1,392,138
5	Unitil Energy Systems Test Year Adjustment		11,313
6	USC Allocated Test Year Software Amortization[4]		105,171
7	Total 2020 Test Year Software Amortization		1,508,621
8	Test Year Amortization Expense Adjustment (Line 3 - Line 7)	$	238,591

Notes
(1) Workpaper W7.2 Line 76
(2) Workpaper W7.4 Line 20
(3) Workpaper W7.1 Line 89
(4) Workpaper W7.3 Line 20

UNITIL ENERGY SYSTEMS, INC.
EXCESS ACCUMULATED DEFERRED INCOME TAX ("ADIT") FLOW BACK
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-18
Table of Contents

	(1)	(2)
LINE NO.	DESCRIPTION	TOTAL
1	Annual Amortization Expense Reduction Related to Excess ADIT Flowback(1)	$ (999,795)

Notes
(1) Refer to Exhibit JAG-6

UNITIL ENERGY SYSTEMS, INC.
PROPERTY TAXES
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-19
Table of Contents

	(1)	(2)	(3)	(4)	(5)
LINE NO.	MUNICIPALITY & STATE	TAXATION PERIOD	LOCAL TAX RATE	ASSESSED VALUATION	TOTAL TAXES[1]
1	Allenstown	4/1 - 3/31	$ 27.27	$ 72,800	$ 1,985
2	Atkinson	1/1 - 12/31	16.24	6,404,700	104,012
3	Boscawen	4/1 - 3/31	24.91	9,837,900	245,062
4	Bow	4/1 - 3/31	23.69	13,389,400	317,195
5	Brentwood	4/1 - 3/31	21.36	189,400	4,046
6	Canterbury	4/1 - 3/31	25.38	3,125,400	79,323
7	Chichester	1/1 - 12/31	21.27	5,774,800	122,830
8	Concord	7/1 - 6/30	24.89	61,631,200	1,534,001
9	Concord	7/1 - 6/30	26.76	83,600	2,237
10	Concord	7/1 - 6/30	28.13	10,358,200	291,376
11	Danville	4/1 - 3/31	24.14	3,885,600	93,798
12	Dunbarton	4/1 - 3/31	20.40	565,000	11,526
13	East Kingston	4/1 - 3/31	20.50	6,782,600	139,043
14	Epsom	4/1 - 3/31	19.92	4,750,000	94,620
15	Exeter	4/1 - 3/31	24.49	613,300	15,020
16	Exeter - Land Only	4/1 - 3/31	22.50	23,387,900	526,228
17	Greenland	4/1 - 3/31	14.58	30,500	445
18	Hampstead	4/1 - 3/31	19.63	464,700	9,122
19	Hampton--Class 4000	4/1 - 3/31	13.93	22,489,300	313,276
20	Hampton--Class 5000	4/1 - 3/31	14.43	11,076,800	159,838
21	Hampton Falls	4/1 - 3/31	19.33	4,260,400	82,354
22	Hopkinton	4/1 - 3/31	27.41	477,700	13,094
23	Kensington	4/1 - 3/31	18.61	10,060,284	187,222
24	Kingston	4/1 - 3/31	18.94	19,784,300	369,094
25	Loudon	4/1 - 3/31	20.73	616,800	12,786
26	Newton	4/1 - 3/31	19.10	6,078,600	116,101
27	North Hampton	4/1 - 3/31	14.80	137,300	2,032
28	Pembroke	4/1 - 3/31	22.77	421,800	9,604
29	Plaistow	4/1 - 3/31	19.60	15,501,960	303,838
30	Salisbury	4/1 - 3/31	22.55	2,689,000	60,637
31	Seabrook	4/1 - 3/31	13.90	19,802,000	275,249
32	South Hampton	4/1 - 3/31	17.14	2,572,400	44,091
33	Stratham	4/1 - 3/31	17.14	9,749,400	167,105
34	Webster	4/1 - 3/31	20.28	2,838,900	57,573
35	State Property Tax[2]	4/1 - 3/31			1,644,889
36	Total			$ 279,903,944	$ 7,410,651
37	Plus: New Exeter DOC Adjustment[3]		$ 24.49	$ 15,517,171	$ 380,016
38	Less: Removal of Old Kensington DOC		$ 18.61	$ 1,015,306	$ 18,895
39	Adjusted Test Year Property Tax Expense				$ 7,771,772
38	Test Year Property Taxes [4] [5]				$ 7,065,052
39	Less: Test Year Property Tax Abatements [4]				38,265
40	Total Test Year Property Tax Expense				$ 7,026,787
41	Total Property Tax Increase (Line 39 - Line 40)				$ 744,985

Notes
(1) Based on final 2020 property tax bills. Company will update for final 2021 property tax bills during pendency of case
(2) Based on current estimated 2021 State Property Tax. Amount will be updated during pendency of case
(3) Estimated Exeter DOC valuation to be updated with actual town valuation during proceeding
(4) Test Year Property Taxes (Line 38) adjusted to exclude inadvertent property tax abatement entry of $4,172.67. This amount was included in the Property Tax Abatements (Line 39) to correct
(5) Test Year Property Taxes reduced by $12,230.60 to remove accrual adjustment entry related to 2019

UNITIL ENERGY SYSTEMS, INC.
PAYROLL TAX ADJUSTMENT - WAGE INCREASES
12 MONTHS ENDED DECEMBER 21, 2020

LINE NO.	(1) DESCRIPTION	(2) Social Security	(3) Medicare	(4) Total
1	Increase in O&M Payroll / Compensation due to Annual Rate Increases [1]	$ 709,516	$ 709,516	
2	Payroll Tax Rates	6.20%	1.45%	
3	Increase in Payroll Taxes	$ 43,990	$ 10,288	$ 54,278

Notes
(1) See Schedule RevReq 3-2 P1

UNITIL ENERGY SYSTEMS, INC.
PAYROLL TAX ADJUSTMENT - EMPLOYEE RETENTION CREDIT
EMPLOYEE RETENTION CREDIT ("ERC") & FAMILY FIRST CORONAVIRUS RESPONSE ACT ("FFCRA")
12 MONTHS ENDED DECEMBER 21, 2020

	(1)		(2)
LINE NO.	DESCRIPTION		TOTAL
1	ERC & FFCRA - UES	$	(143,511)
2	Capitalization Rate		64.25%
3	Capitalized Amount		(92,206)
4	Net Expense - UES		(51,305)
5	Unitil Service ERC Allocated to UES		
6	Total Unitil Service ERC	$	(279,213)
7	UES Apportionment		27.50%
8	Expense Apportioned to UES	$	(76,784)
9	Capitalization Rate		28.45%
10	UES Capitalization		(21,845)
11	UES Net ERC	$	(54,939)
12	Removal of Total ERC & FFCRA from Test Year	$	106,244

UNITIL ENERGY SYSTEMS, INC.
COMPUTATION OF FEDERAL AND STATE INCOME TAXES
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-21
Page 1 of 4
Table of Contents

LINE NO.	(1) DESCRIPTION		(2) AMOUNT
1	Increases / (Decreases) To Revenue		
2	Non-Distribution Bad Debt		(143,623)
3	Unbilled Revenue		(137,189)
4	New DOC Rent Revenue		313,007
5	Late Fee Adjustment		180,938
6	Total Revenue Adjustments	$	213,133
7	Increases / (Decreases) To Expenses		
8	Payroll	$	709,516
9	VMP Expense		1,406,427
10	Medical & Dental Insurances		483,155
11	Pension		62,288
12	PBOP		(41,636)
13	SERP		85,989
14	401K		41,844
15	Deferred Comp Expense		64,957
16	Property & Liability Insurances		72,468
17	DOC Expense Adjustment		(1,968)
18	NHPUC Regulatory Assessment		159,383
19	Dues & Subscriptions		(14,473)
20	Pandemic Costs		(39,857)
21	Claims & Litigation Adjustment		44,072
22	Severance Expense		(40,395)
23	Distribution Bad Debt		134,563
24	Non-Distribution Bad Debt		(143,623)
25	Arrearage Management Program (AMP) Implementation Cost		459,000
26	Inflation Allowance		128,368
27	Depreciation Annualization		908,712
28	Proposed Depreciation Rates		(789,749)
29	Software Amortization		238,591
30	Excess ADIT Flowback		(999,795)
31	Property Taxes		744,985
32	Payroll Taxes - Wage Increases		54,278
33	Payroll Taxes - Employee Retention Credits		106,244
34	Change In Interest Exp (Refer to Schedule RevReq-3-21 Page 2)		352,512
35	Total Expense Adjustments	$	4,185,854
36	Increase / (Decrease) In Taxable Income	$	(3,972,721)
37	Effective Federal Income Tax Rate(1)		19.38%
38	NH State Tax Rate(2)		7.70%
	Federal Income & NH State Tax		
39	Effective Federal Income Tax	$	(770,033)
40	NH State Tax		(305,900)
41	Increase (Decrease) In Income Taxes	$	(1,075,932)
	Notes		
42	Federal Income Tax Rate		21.00%
43	Federal Benefit of State Tax -(Line 43 * Line 46)		-1.62%
44	(1) Effective Federal Income Tax Rate		19.38%
45	(2) State Income Tax Rate		7.70%
46	Unitil Energy Systems Tax Rate (Line 45 + Line 46)		27.08%

UNITIL ENERGY SYSTEMS, INC.
CHANGE IN INTEREST EXPENSE APPLICABLE TO INCOME TAX COMPUTATION
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-21

LINE NO.	(1) DESCRIPTION	(2) AMOUNT
1	Ratemaking Interest Synchronization:	
2	Rate Base [(1)]	$ 226,030,082
3	Cost of Debt In Proposed Rate of Return [(2)]	2.58%
4	Interest Expense for Ratemaking	5,830,578
5	Test Year Interest Expense:	
6	Interest Charges (427-432)	$ 5,478,066
7	Increase / (Decrease) in Interest Expense	$ 352,512

Notes
(1) Schedule RevReq-4
(1) Schedule RevReq-5

UNITIL ENERGY SYSTEMS, INC.
COMPUTATION OF FEDERAL AND STATE INCOME TAXES
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-3-21
Page 3 of 4
Table of Contents

LINE NO	(1) DESCRIPTION	(2) TEST YEAR ACTUAL	(3) PRO-FORMA ADJUSTMENTS	(4) TEST YEAR UTILITY
1	Net Income	$ 8,133,382	$ -	$ 8,133,382
2	Federal Income Tax-Current	(1,161,380)	-	(1,161,380)
3	NH State Income Tax-Current	(1,088,917)	-	(1,088,917)
4	NH State Business Enterprise Credit Against NH BPT	78,000	-	78,000
5	Deferred Federal Income Tax	3,329,959	-	3,329,959
6	Deferred State Income Tax	1,873,334	-	1,873,334
7	Net Income Before Income Taxes	11,164,379	-	11,164,379
8	*Permanent Items*			
9	Lobbying	34,375	-	34,375
10	Parking Lot Disallowance	1,368	-	1,368
11	Penalties	-	-	-
12	State Regulatory Asset Amortization	-	-	-
13	Unallowable Meals	107	-	107
14	Total Permanent Items	35,850	-	35,850
15	*Temporary Differences*			
16	Accrued Revenue	666,606	-	666,606
17	Bad Debt	394,494	-	394,494
18	Bad Debt Reg Asset	(143,623)		(143,623)
19	Debt Discount	1,920	-	1,920
20	Deferred Rate Case Costs	(5,850)	-	(5,850)
21	DER Investment Amortization	11,020	-	11,020
22	Indenture Costs	28,704	-	28,704
23	FASB 87-Pensions	(394,249)	-	(394,249)
24	Prepaid Property Taxes	192,963	-	192,963
25	PBOP SFAS 106	757,586	-	757,586
26	Storm Restoration	1,470,280	-	1,470,280
27	Utility Plant Differences	(1,867,587)	-	(1,867,587)
28	Total Temporary Differences	1,112,264	-	1,112,264
29	*Federal And State Tax Differences*			
30	Tax Depreciation	(5,044,874)	-	(5,044,874)
31	Total Federal And State Tax Differences	(5,044,874)	-	(5,044,874)
32	State Taxable Base Income	7,267,619	-	7,267,619
33	State Business Profits Tax - Current	559,607	-	559,607
34	Less: Business Enterprise Tax	78,000	-	78,000
35	Total State Tax Expense	481,607	-	481,607
36	Federal Taxable Income Base Before Federal And State Tax Differences	6,708,012	-	6,708,012
37	Less: Federal And State Tax Differences	(5,044,874)	-	(5,044,874)
38	Federal Taxable Income Base	11,752,886	-	11,752,886
39	Federal Income Tax-Current	2,468,106	-	2,468,106
40	*Summary Of Utility Income Taxes:*			
41	Federal Income Tax-Current	2,449,098	-	2,449,098
42	Federal Income Tax-Prior	(4,293,279)	-	(4,293,279)
43	Federal Income Tax-NOL	663,793	-	663,793
44	Federal Amount To Non-Distribution Operations	19,008	(19,008)	-
45	State Business Profits Tax-Current	474,055	-	474,055
46	State Business Profits Tax-Prior	(1,570,523)	-	(1,570,523)
47	State Amount To Non-Distribution Operations	7,551	(7,551)	-
48	Deferred Federal Income Tax	(297,166)	-	(297,166)
49	Deferred Federal Income Tax-Prior	4,290,918	-	4,290,918
50	Deferred Federal Income Tax-NOL	(663,793)	-	(663,793)
51	Deferred State Business Profits Tax	302,811	-	302,811
52	Deferred State Business Profits Tax-Prior	1,570,523	-	1,570,523
53	Total Income Taxes	$ 2,952,997	$ (26,560)	$ 2,926,437

UNITIL ENERGY SYSTEMS, INC.
PRIOR YEAR INCOME TAXES
12 MONTHS ENDED DECEMBER 31, 2020

	(1)	(2)
LINE NO	DESCRIPTION	ACTUAL
1	Remove Prior Year Federal Income Taxes	$ 4,293,279
2	Remove Prior Year State Income Taxes	1,570,523
3	Remove Prior Year Deferred Federal Income Taxes	(4,290,918)
4	Remove Prior Year Deferred State Income Taxes	(1,570,523)
5	Total	$ 2,361

UNITIL ENERGY SYSTEMS, INC.
RATE BASE
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-4
Table of Contents

LINE NO.	(1) DESCRIPTION	(2) REFERENCE	(3) TEST YEAR AVERAGE [1]	(4) 5 QUARTER AVERAGE	(5) RATE BASE AT DECEMBER 31, 2020	(6) PRO FORMA ADJUSTMENTS	(7) PRO FORMA RATE BASE AT DECEMBER 31, 2020
1	Utility Plant In Service	Schedule RevReq-4-1	$ 385,883,446	$ 378,293,580	$ 408,325,193	$ (411,070)	$ 407,914,123
2	Less: Reserve for Depreciation	Schedule RevReq-4-1	134,753,201	136,143,968	138,059,087	-	138,059,087
3	Net Utility Plant		251,130,244	242,149,612	270,266,106	(411,070)	269,855,036
4	Add: M&S Inventories	Schedule RevReq-4-1	$ 2,022,364	$ 1,998,245	$ 2,032,252	$ -	$ 2,032,252
5	Cash Working Capital [2]	Schedule RevReq-4-2	2,383,150	2,383,150	2,383,150	967,154	3,350,304
6	Prepayments	Schedule RevReq-4-1	4,840,442	4,956,633	4,508,744	-	4,508,744
7	Sub-Total		9,245,956	9,338,028	8,924,147	967,154	9,891,301
8	Less: Net Deferred Income Taxes	Schedule RevReq-4-1	$ 36,365,292	$ 36,267,391	$ 38,338,666	$ (71,351)	$ 38,267,315
9	Less: Excess Deferred Income Taxes	Schedule RevReq-4-1	16,601,346	16,601,346	16,601,346	(1,928,356)	14,672,991
10	Plus: Deferred Income Taxes Debit	Schedule RevReq-4-1	146,198	134,890	150,098	-	150,098
11	Less: Customers Deposits	Schedule RevReq-4-1	482,702	480,878	371,830	-	371,830
12	Less: Customer Advances	Schedule RevReq-4-1	539,816	498,063	554,217	-	554,217
13	Rate Base		$ 206,533,242	$ 197,774,851	$ 223,474,292	$ 2,555,790	$ 226,030,082
14	Net Operating Income Applicable To Rate Base		$ 11,613,315	$ 11,613,315	$ 11,613,315		$ 9,066,677
15	Rate of Return		5.62%	5.87%	5.20%		4.01%

Notes
(1) Two Point Average
(2) Computed Working Capital Based on Test Year O&M Expenses

UNITIL ENERGY SYSTEMS, INC.
RATE BASE ITEMS
QUARTERLY BALANCES

Schedule RevReq-4-1
Table of Contents

LINE NO.	(1) DESCRIPTION	(2) DECEMBER 31 2019	(3) MARCH 31 2020	(4) JUNE 30 2020	(5) SEPTEMBER 30 2020	(6) DECEMBER 31 2020	(7) 5 QUARTER AVERAGE
1	Utility Plant in Service						
2	Classified	$ 350,524,447	$ 356,913,902	$ 357,270,455	$ 361,417,472	$ 379,030,364	$ 361,031,328
3	Completed Construction Not Classified	12,917,251	13,216,745	15,748,937	15,133,497	29,294,829	17,262,252
4	Total Utility Plant in Service	363,441,698	370,130,647	373,019,392	376,550,969	408,325,193	378,293,580
5	Depreciation & Amortization Reserves	$ (131,447,315)	$ (134,081,053)	$ (137,117,184)	$ (140,015,203)	$ (138,059,087)	$ (136,143,968)
6	Add:						
7	M&S Inventories						
8	Materials and Supplies	1,174,870	1,262,158	1,389,123	1,192,748	1,206,272	1,245,034
9	Stores	189,428	259,182	177,187	39,287	201,952	173,407
10	Clearing Accounts	648,177	1,405,667	670,379	(449,234)	624,028	579,803
11	Total M&S Inventories	$ 2,012,476	$ 2,927,007	$ 2,236,689	$ 782,802	$ 2,032,252	$ 1,998,245
12	Prepayments	5,172,139	5,243,990	4,888,628	4,969,664	4,508,744	4,956,633
13	Cash Working Capital	2,383,150	2,383,150	2,383,150	2,383,150	2,383,150	2,383,150
14	Less: Rate Base Deferred Taxes						
15	Total Deferred Income Taxes	16,461,001	15,482,438	17,529,426	18,327,330	20,259,723	17,611,984
16	Less: Storm Damage DFIT	1,527,288	1,446,855	1,340,817	1,223,261	1,129,092	1,333,463
17	Less: SFAS 158 DIT	(13,086,349)	(12,969,759)	(13,006,813)	(13,045,482)	(14,498,720)	(13,321,425)
18	Less: SFAS 106 DIT	2	2	2	479,390	0	95,879
19	Less: SFAS 158 DIT	1	1	1	133,801	0	26,761
20	Less: Prepaid Property Taxes	459,538	125,886	374,327	226,716	407,278	318,749
21	Less: (ASC 740) Gross up[(1)]	(6,150,857)	(6,150,857)	(6,150,857)	(6,150,857)	(6,150,857)	(6,150,857)
22	Less: Rate Case Expense	(1)	(1)	(1)	(1)	1,584	316
23	Less: Bad Debt Regulatory Asset	20,080	16,172	15,393	15,393	58,978	25,203
24	Less: Accrued Revenue - Purchased Power	(700,619)	(1,322,203)	(1,914,021)	(1,954,342)	973,702	(983,497)
25	Total Rate Base Deferred Taxes	$ 34,391,918	$ 34,336,343	$ 36,870,579	$ 37,399,450	$ 38,338,666	$ 36,267,391
26	Less: Excess Deferred Income Taxes[(1)]	16,601,346	16,601,346	16,601,346	16,601,346	16,601,346	16,601,346
27	Plus: Deferred Taxes Debit	142,298	120,514	129,066	132,475	150,098	134,890
28	Less: Customer Deposits	593,573	545,176	470,020	423,792	371,830	480,878
29	Less: Customer Advances	525,416	444,982	476,559	489,144	554,217	498,063
30	Rate Base	$ 189,592,193	$ 194,796,409	$ 191,121,237	$ 189,890,125	$ 223,474,292	$ 197,774,851

Notes:
(1) ASC 740 Gross up excluded from Total Rate Base Deferred Taxes (Line 11), but included in Excess Deferred Income Tax Line (Line 18)

UNITIL ENERGY SYSTEMS, INC.
CASH WORKING CAPITAL
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-4-2
Table of Contents

	(1)	(2)	(3)	(4)	(5)
LINE NO.	DESCRIPTION	REFERENCE	TEST YEAR ACTUAL	PROFORMA ADJUSTMENTS	TEST YEAR AS PROFORMED
1	O&M Expense	Schedule RevReq-2	22,222,234	2,061,610	24,283,845
2	Tax Expense	Schedule RevReq-2	4,889,822	8,941,277	13,831,098
3	Total		$ 27,112,056	$ 11,002,887	$ 38,114,943
4	Cash Working Capital Requirement:				
5	Other O&M Expense Days Lag (1) / 366	32.17 days	8.79%	8.79%	8.79%
6	Total Cash Working Capital	Line 5 X Line 3	$ 2,383,150	$ 967,154	$ 3,350,303

Notes
(1) Refer to Lead-Lag Study in Direct Testimony of Daniel Hurstak

UNITIL ENERGY SYSTEMS, INC.
KENSINGTON DISTRIBUTION OPERATING CENTER ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-4-3
Table of Contents

	(1)	(2)	
LINE NO.	**DESCRIPTION**		**AMOUNT**
1	Kensington DOC Value as of 12/31/2020		
2	389-General & Misc. Structure	$	(9,679)
3	390-Structures		(978,535)
4	Total Kensington DOC Value as of 12/31/2020	$	(988,214)
5	Net Tax Value as of 12/31/2020	$	715,083
6	Change in Accumulated Deferred Taxes[1]		(71,351)

Notes
(1) (Line 3 + Line 5) x Effective Tax Rate of 27.083%

UNITIL ENERGY SYSTEMS, INC.
EXETER DISTRIBUTION OPERATING CENTER ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-4-4
Table of Contents

	(1)		(2)
LINE NO.	DESCRIPTION		AMOUNT
1	Exeter DOC Additions 1/1/2021-2/28/2021		
2	390-Structures	$	496,301
3	391.1-Office Furniture & Equipment		76,307
4	393-Stores Equip		4,536
5	Total Exeter DOC Additions 1/1/2021-2/28/2021	$	577,144

UNITIL ENERGY SYSTEMS, INC.
EXCESS ACCUMULATED DEFERRED INCOME TAXES ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-4-5
Table of Contents

	(1)	(2)
LINE NO.	DESCRIPTION	AMOUNT
1	Major Storm Cost Reserve Balance as of 12/31/2020	$ 3,275,423
2	Excess ADIT flow back for 2018-2020 [1]	2,644,590
3	Adjusted Major Storm Cost Reserve Balance as of 12/31/2020	630,833
4	Reduction to Excess Deferred Income Tax Liability	(2,644,590)
5	Increase to Accumulated Deferred Income Taxes [2]	716,234
6	Net Decrease to Excess Deferred Income Tax Liability	(1,928,356)

Notes
(1) Refer to Exhibit JAG-6
(2) - Line 4 x Effective Tax Rate of 27.083%

UNITIL ENERGY SYSTEMS, INC.
WEIGHTED AVERAGE COST OF CAPITAL
5 QUARTER AVERAGE ENDED DECEMBER 31, 2020 PRO FORMA

Schedule RevReq-5
Table of Contents

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
LINE NO.	DESCRIPTION	AMOUNT	PROFORMA ADJUSTMENT	PROFORMED AMOUNT	WEIGHT	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	REFERENCE
1	Common Stock Equity	$ 101,242,877	$ -	$ 101,242,877	52.91%	10.00%	5.29%	Schedule RevReq 5-1
2	Preferred Stock Equity	188,700	-	188,700	0.10%	6.00%	0.01%	Schedule RevReq 5-1 and 5-6
3	Long Term Debt	93,400,000	(3,500,000)	89,900,000	46.99%	5.49%	2.58%	Schedule RevReq 5-1 and 5-4
4	Short Term Debt	-	-	-	0.00%	1.68%	0.00%	Schedule RevReq 5-1 and 5-5
5	Total	$ 194,831,577	$ (3,500,000)	$ 191,331,577	100.00%		7.88%	

UNITIL ENERGY SYSTEMS, INC.
CAPITAL STRUCTURE FOR RATEMAKING PURPOSES
5-QUARTER AVERAGE ENDED DECEMBER 31, 2020 PRO FORMA

Schedule RevReq-5-1
Table of Contents

LINE NO.	(1) DESCRIPTION	(2) DECEMBER 31 2019	(3) MARCH 31 2020	(4) JUNE 30 2020	(5) SEPTEMBER 30 2020	(6) DECEMBER 31 2020	(7) 5 QUARTER AVERAGE	(8) PROFORMA ADJUSTMENT	(9) PROFORMA AMOUNT
1	Common Stock Equity								
2	Common Stock	$ 2,442,426	$ 2,442,426	$ 2,442,426	$ 2,442,426	$ 2,442,426	$ 2,442,426	$ -	$ 2,442,426
3	Premium on Capital Stock	1,005,875	1,005,875	1,005,875	1,005,875	1,005,875	1,005,875	-	1,005,875
4	Misc. Paid In Capital	51,028,170	51,028,170	56,028,170	56,028,170	58,778,170	54,578,170	-	54,578,170
5	Common Stock Expense	(94,845)	(94,845)	(94,845)	(94,845)	(94,845)	(94,845)	-	(94,845)
6	Retained Earnings	42,949,034	42,237,826	42,838,727	44,310,367	44,220,302	43,311,251	-	43,311,251
7	Total Common Stock Equity	97,330,660	96,619,452	102,220,353	103,691,992	106,351,928	101,242,877	-	101,242,877
8	Preferred Stock Equity	188,700	188,700	188,700	188,700	188,700	188,700	-	188,700
9	Long-Term Debt	87,500,000	82,500,000	82,500,000	108,000,000	106,500,000	93,400,000	(3,500,000)	89,900,000
10	Short-Term Debt (1)	-	-	-	-	-	-	-	-
11	Total	$ 185,019,360	$ 179,308,152	$ 184,909,053	$ 211,880,692	$ 213,040,628	$ 194,831,577	$ (3,500,000)	$ 191,331,577
12	Capital Structure Ratios								
13	Common Stock Equity	52.61%	53.88%	55.28%	48.94%	49.92%	51.96%		52.91%
14	Preferred Stock Equity	0.10%	0.11%	0.10%	0.09%	0.09%	0.10%		0.10%
15	Long-Term Debt	47.29%	46.01%	44.62%	50.97%	49.99%	47.94%		46.99%
16	Short-Term Debt (1)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
17	Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%		100.00%

Notes
(1) For ratemaking purposes the Company has imputed zero short-term debt

UNITIL ENERGY SYSTEMS, INC.
HISTORICAL CAPITAL STRUCTURE
DECEMBER 31, 201X

Schedule RevReq-5-2
Table of Contents

LINE NO.	(1) DESCRIPTION	(2) 2015	(3) 2016	(4) 2017	(5) 2018	(6) 2019
1	Common Stock Equity	$ 77,284,950	$ 79,155,139	$ 80,739,631	$ 83,926,900	$ 97,330,660
2	Preferred Stock Equity	189,800	189,300	189,300	189,300	188,700
3	Long-Term Debt	77,000,000	74,000,000	72,500,000	96,000,000	87,500,000
4	Total	$ 154,474,750	$ 153,344,439	$ 153,428,931	$ 180,116,200	$ 185,019,360
5	Short-Term Debt (Year-End)	8,774,322	16,772,688	21,386,504	-	13,065,032

UNITIL ENERGY SYSTEMS, INC.
HISTORICAL CAPITALIZATION RATIOS
DECEMBER 31, 201X

Schedule RevReq-5-3
Table of Contents

LINE NO.	(1) DESCRIPTION	(2) 2015	(3) 2016	(4) 2017	(5) 2018	(6) 2019
1	Common Stock Equity	50.03%	51.62%	52.62%	46.60%	52.61%
2	Preferred Stock Equity	0.12%	0.12%	0.12%	0.11%	0.10%
3	Long-Term Debt	49.85%	48.26%	47.25%	53.30%	47.29%
4	Total	100.00%	100.00%	100.00%	100.00%	100.00%

UNITIL ENERGY SYSTEMS, INC.
WEIGHTED AVERAGE COST OF LONG-TERM DEBT
DECEMBER 31, 2020 PRO FORMA

Schedule RevReq-5-4
Table of Contents

LINE NO.	(1)	(2) ISSUE	(3) DATE ISSUED	(4) TERM	(5) FACE VALUE	(6) OUTSTANDING AMOUNT	(7) PROFORMA ADJUSTMENT	(8) PROFORMED OUTSTANDING AMOUNT	(9) ISSUANCE COSTS	(10) NET PROCEEDS RATIO [(5)-(9)/(5)]	(11) UNAMORTIZED ISSUANCE COSTS	(12) NET PROCEEDS OUTSTANDING (8)-(11)	(13) ANNUAL ISSUANCE COST	(14) ANNUAL INTEREST COST Rate * (8)	(15) TOTAL ANNUAL COST (13)+(14)	(16) COST RATE BASED ON NET PROCEEDS (15)/[(8)-(11)]
1	8.49%	Series I	10/14/1994	30 Yrs	$ 6,000,000	$ 1,200,000	$ (600,000)	$ 600,000	$ 141,750	97.64%	$ 18,034	$ 581,966	$ 4,756	$ 50,940	$ 55,696	9.57%
2	6.96%	Series J	9/1/1998	30 Yrs	10,000,000	8,000,000	(1,000,000)	7,000,000	343,727	96.56%	88,011	6,911,989	11,479	487,200	498,679	7.21%
3	8.00%	Series K	5/1/2001	30 Yrs	7,500,000	7,500,000	-	7,500,000	236,989	96.84%	50,381	7,449,619	4,876	600,000	604,876	8.12%
4	8.49%	Series L	10/14/1994	30 Yrs	9,000,000	1,800,000	(900,000)	900,000	193,809	97.85%	24,599	875,401	6,488	76,410	82,898	9.47%
5	6.96%	Series M	9/1/1998	30 Yrs	10,000,000	8,000,000	(1,000,000)	7,000,000	230,507	97.69%	59,076	6,940,924	7,706	487,200	494,906	7.13%
6	8.00%	Series N	5/1/2001	30 Yrs	7,500,000	7,500,000	-	7,500,000	111,917	98.51%	40,280	7,459,720	3,898	600,000	603,898	8.10%
7	6.32%	Series O	9/26/2006	30 Yrs	15,000,000	15,000,000	-	15,000,000	280,242	98.13%	146,737	14,853,263	9,341	948,000	957,341	6.45%
8	4.18%	Series Q	11/30/2018	30 Yrs	30,000,000	30,000,000	-	30,000,000	535,964	98.21%	498,784	29,501,216	17,865	1,254,000	1,271,865	4.31%
9	3.58%	Series R	9/15/2020	20 Yrs	27,500,000	27,500,000	-	27,500,000	173,526	99.37%	170,634	27,329,366	8,676	984,500	993,176	3.63%
10	12th Supplemental		12/1/2002	24 Yrs					464,633		158,265	(158,265)	21,582		21,582	
11		Total			$ 122,500,000	$ 106,500,000	$ (3,500,000)	$ 103,000,000	$ 2,713,064		$ 1,254,801	$ 101,745,199			$ 5,584,917	5.49%

UNITIL ENERGY SYSTEMS, INC.
COST OF SHORT-TERM DEBT
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-5-5
Table of Contents

LINE NO.	(1) MONTH	(2) MONTH-END AMOUNT OUTSTANDING	(3) AVERAGE DAILY BORROWINGS	(4) MONTHLY SHORT-TERM INTEREST	(5) INTEREST RATE(1)
1	January 2020	15,981,465	13,423,371	$ 32,462	2.86%
2	February 2020	18,329,433	15,403,679	34,383	2.82%
3	March 2020	25,006,584	22,479,815	40,533	2.13%
4	April 2020	26,439,328	24,786,356	38,939	1.92%
5	May 2020	26,575,577	25,292,157	29,279	1.37%
6	June 2020	23,423,291	23,096,051	25,174	1.33%
7	July 2020	26,686,489	25,491,071	28,529	1.32%
8	August 2020	29,757,846	29,264,455	32,399	1.31%
9	September 2020	4,767,278	17,205,102	18,331	1.30%
10	October 2020	8,896,119	7,217,071	7,906	1.29%
11	November 2020	6,996,466	6,214,346	6,564	1.29%
12	December 2020	8,176,368	6,924,815	7,590	1.29%
13	Average for the Year		18,066,524		1.68%

Notes
(1) The Interest Rate is calculated as follows: [Column (4) / # of days in month * 366] / Column (3).

UNITIL ENERGY SYSTEMS, INC.
WEIGHTED AVERAGE COST OF PREFERRED STOCK
DECEMBER 31, 2020

Schedule RevReq-5-6
Table of Contents

LINE NO.	(1) SERIES	(2) DATE ISSUED	(3) FACE VALUE	(4) ISSUANCE COSTS	(5) NET PROCEEDS RATIO [(3)-(4)/(3)]	(6) OUTSTANDING AMOUNT	(7) UNAMORTIZED ISSUANCE COSTS	(8) NET PROCEEDS OUTSTANDING (6)-(7)	(9) ANNUAL ISSUANCE COST	(10) ANNUAL DIVIDEND EXPENSE Rate * (6)	(11) TOTAL ANNUAL COST (11)+(12)	(12) COST RATE BASED ON NET PROCEEDS (11)/[(6)-(7)]
1	6.00%	1905-1926	$ 188,700	N/A	100.00%	$ 188,700	N/A	$ 188,700	$ -	$ 11,322	$ 11,322	6.00%
2	Total		$ 188,700	$ -		$ 188,700	$ -	$ 188,700	$ -	$ 11,322	$ 11,322	6.00%

UNITIL ENERGY SYSTEMS, INC.
COST OF COMMON EQUITY CAPITAL
12 MONTHS ENDED DECEMBER 31, 2020

Schedule RevReq-5-7
Table of Contents

THE INFORMATION CONCERNING THE COST OF COMMON EQUITY CAPITAL IS PROVIDED IN THE TESTIMONY AND EXHIBITS OF MS. JENNIFER NELSON

UNITIL ENERGY SYSTEMS, INC.
RATE CASE EXPENSE COSTS
PROJECTED THROUGH THE COMPLETION OF THE CASE

Schedule RevReq-6
Table of Contents

LINE NO.	(1) DESCRIPTION	(2) AMOUNT
1	Cost Studies and Rate Design	215,000
2	Decoupling	45,000
3	Depreciation Study	80,000
4	Return On Equity	110,000
5	Administration and Miscellaneous Expenses	5,000
6	Commission Costs	300,000
7	Total	755,000

UNITIL ENERGY SYSTEMS, INC.
2021 RATE PLAN OUTLINE

1.0 PURPOSE AND EFFECTIVE DATE

1.1 Purpose

The purpose of the 2021 Rate Plan is to establish a procedure that allows Unitil Energy Systems, Inc. ("Unitil Energy" or the "Company"), subject to the jurisdiction of the New Hampshire Public Utilities Commission (the "Commission"), to obtain recovery of the incremental revenue requirement associated with capital additions and the related expenses, as defined herein. Additionally, the 2021 Rate Plan provides for consumer protections, including a cap for rate increases as well as earnings sharing.

1.2 Effective Date

The rate adjustments associated with each Investment Year beginning on and after January 1, 2021 shall be effective April 1 of the following year with a compliance filing due by the last day of January as outlined below:

Investment Year	Rate Year	Compliance Filing Due
January 1-December 31, 2021	April 1, 2022-March 31, 2023	January 31, 2022[1]
January 1-December 31, 2022	April 1, 2023-March 31, 2024	January 31, 2023
January 1-December 31, 2023	April 1, 2024-March 31, 2025	January 31, 2024

2.0 ELIGIBLE PLANT ADDITIONS

All utility Non-Growth Plant Additions will be eligible for recovery upon Commission review and approval of the annual compliance filing. The 2021 Rate Plan will recover the revenue requirement associated with the annual Change in Net Plant associated with the Non-Growth Plant Additions as a percent of Total Plant Additions.

[1] The Company proposes to present Investment Year 2021 during the rate case proceeding for effect with permanent rates on April 1, 2022.

3.0 REVENUE REQUIREMENT

An illustrative calculation of the Revenue Requirement is provided in Schedule CGDN-2. Revenue Requirement is the sum of the following for each Investment Year:

- Pre-Tax Rate of Return applied to the annual Change in Net Plant multiplied by a factor calculated annually as Non-Growth Plant Additions divided by Total Plant Additions;
- Depreciation Expense on annual Plant Additions multiplied by a factor calculated annually as Non-Growth Plant Additions divided by Total Plant Additions; and
- Property Taxes on the annual Change in Net Plant multiplied by a factor calculated annually as Non-Growth Plant Additions divided by Total Plant Additions.

4.0 VEGETATION MANAGEMENT AND RELIABILITY ENHANCEMENT EXPENSES

In the Company's annual compliance filing, the Company will continue to reconcile actual vegetation management and reliability enhancement O&M expenses with $6,265,166 of cost recovery included in rates in Docket No. DE 21-030. The reconciliation will take into account the amount of recovery included in rates in Docket No. 16-384 for the period of January 1, 2021 through May 31, 2021 and the amount of recovery included in rates in Docket No. DE 21-030 for the period of June 1, 2021 and forward. Any over- or under-collection shall be reflected in the Company's External Delivery Charge mechanism. With approval of the Commission, the Company may credit unspent amounts to future vegetation management program O&M expenditures.

5.0 CUSTOMER PROTECTIONS

5.1 Rate Cap

Changes to distribution rates as calculated by the 2021 Rate Plan in any Rate Year are limited to a rate cap of 2.5% of the Company's prior year total electric operating revenue, with revenue for externally supplied customers being adjusted by imputing the Company's default service charges for that period. Any part of the Revenue Requirement that is above the cap will be deferred at the Company's cost of capital established in Docket No. DE 21-030.

5.2 Earnings Sharing

Earnings sharing will be triggered if return on equity as submitted in its annual PUC 308.11 F-1 filing exceeds 11%. If return on equity exceeds 11%, then excess earnings will be shared equally between the distribution ratepayers and the Company.

5.3 Stay Out Provision

Except as specifically provided for under the 2021 Rate Plan, the Company may not petition the Commission for distribution base rate adjustments through the end of calendar year 2024. However, if the Company's return on equity is below 7% as submitted in the Company's annual PUC 308.11 F-1 filing, then the Company may petition the Commission for a distribution base rate adjustment before 2024.

5.4 Exogenous Events

During the term of this 2021 Rate Plan, the Company will be allowed to adjust distribution rates upward or downward resulting from a singular (not collective) exogenous event, as defined herein. For any of the events defined as a State Initiated Cost Change, Federally Initiated Cost Change, Regulatory Cost Reassignment, or Externally Imposed Accounting Rule Change, during the term of this Plan, the Company will be allowed to adjust distribution rates upward or downward (to the extent that the revenue impact of such event is not otherwise captured through another rate mechanism that has been approved by the Commission) if the total distribution revenue impact (positive or negative) of such event exceeds $200,000.

6.0 RATE DESIGN

For the rate adjustments in section 3.0 above, the revenue requirement increase shall be applied proportionally to all customer classes based on distribution revenue, using current distribution rates and test year billing determinants established in Docket No. DE 21-030. The increase shall be collected through customer, demand or energy charges as applicable for all rate classes, except for outdoor lighting, where the increase shall be applied on an equal percentage basis to all luminaire charges.

For earnings sharing and exogenous events in section 5.0 above, rate adjustments shall also be applied proportionally to all customer classes based on distribution revenue, using current distribution rates and test year billing determinants established in Docket No. DE 21-030. The charge or credit shall be made through demand or energy usage charges, as applicable, for all rate classes, except for outdoor lighting, where the amount shall be applied on an equal percentage basis to all luminaire charges. There will be no change in the customer charge.

7.0 DEFINITIONS

1) Accumulated Depreciation is the cumulative net credit balance arising from the provision for Depreciation Expense.

2) Change in Net Plant is the change in Ending Net Utility Plant from one Investment Year to the next which accounts for Plant Additions as well as Accumulated Depreciation.

3) Depreciation Expense is established at 3.36% and is based on the average depreciation rate provided in Docket No. DE 21-030.

4) Ending Net Utility Plant is the "per books" utility Plant Additions for plant in service after Accumulated Depreciation is deducted.

5) Externally Imposed Accounting Rule Change shall be deemed to have occurred if the Financial Accounting Standards Board or the Securities and Exchange Commission adopts a rule that requires utilities to use a new accounting rule that is not being utilized by the Company as of January 1, 2022.

6) Federally Initiated Cost Change shall mean any externally imposed changes in the federal tax rates, laws, regulations, or precedents governing income, revenue, or sales taxes or any changes in federally imposed fees, which impose new obligations, duties or undertakings, or remove existing obligations, duties or undertakings, and which individually decrease or increase the Company's distribution costs, revenue, or revenue requirement.

7) Investment Year is the annual period beginning January 1 and ending December 31 of each calendar year 2021 through 2023 for which capital investments are made by the Company and placed in service.

8) Plant Additions are the capitalized costs of plant placed in service as recorded on the Company's books during the Investment Year. In Investment Year 2021, $577,144 of additions related to the new Exeter Distribution Operating Center is excluded as it is embedded in base rates via Docket No. DE 21-030.

9) Pre-Tax Rate of Return is 9.84% which is established based on the cost of capital and a tax gross up on common stock equity per Docket No. DE 21-030.

10) Property Taxes are established at a rate of 2.74%, representing the average system property taxes paid as a percent of net plant in the test year for Docket No. DE 21-030. This percentage will be updated annually to reflect the most recent property tax costs.

11) Rate Year is the annual period April 1 through March 31, following the Investment Year.

12) State Initiated Cost Change shall mean any externally imposed changes in state or local law or regulatory mandates or changes in other precedents governing income, revenue, sales, franchise, or property or any new or amended regional, state or locally imposed fees (but excluding the effects of routine annual changes in municipal, county and state property tax

rates and revaluations), which impose new obligations, duties or undertakings, or remove existing obligations, duties or undertakings, and which individually decrease or increase the Company's distribution costs, revenue, or revenue requirement.

13) Regulatory Cost Reassignment shall mean the reassignment of costs and/or revenues now included in the generation, transmission, or distribution functions to or away from the distribution function by the Commission, FERC, NEPOOL, the ISO or any other official agency having authority over such matters.

Unitil Energy Systems, Inc.
Docket DE 21-030
Schedule CGDN-2
Page 1 of 3

UNITIL ENERGY SYSTEMS, INC.
ILLUSTRATIVE REVENUE REQUIREMENT
2021 RATE PLAN

LINE NO.	DESCRIPTION		STEP ADJ #1 INVESTMENT YEAR 2021	STEP ADJ #2 INVESTMENT YEAR 2022	STEP ADJ #3 INVESTMENT YEAR 2023
	RATE EFFECTIVE DATE		4/1/2022	4/1/2023	4/1/2024
1	Beginning Utility Plant [1]		$ 407,914,123	$ 439,000,400	$ 476,526,965
2	Plant Additions [2]		31,086,277	37,526,565	36,977,986
3	Ending Utility Plant		439,000,400	476,526,965	513,504,951
4	Beginning Accumulated Depreciation [3]		(138,059,087)	(151,381,091)	(165,855,790)
5	Depreciation Expense		(13,322,003)	(14,474,699)	(15,726,376)
6	Ending Accumulated Depreciation		(151,381,091)	(165,855,790)	(181,582,166)
7	Ending Net Utility Plant		287,619,309	310,671,175	331,922,785
8	Change in Net Plant		17,764,273	23,051,866	21,251,610
9	Non-Growth % Change in Net Plant [4]		84%	86%	83%
10	Non-Growth Change in Net Plant		14,918,356	19,841,526	17,702,557
11	Pre-Tax Rate of Return		9.84%	9.84%	9.84%
12	Return and Taxes		1,468,315	1,952,871	1,742,346
13	Depreciation Expense on Non-Growth Plant Additions at	3.36%	877,165	1,085,293	1,034,967
14	Property Taxes on Non-Growth Change in Net Plant at	2.74%	408,763	543,658	485,050
15	Revenue Requirement Increase		$ 2,754,244	$ 3,581,822	$ 3,262,364
16	Rate Cap Limit:				
17	Total Electric Operating Revenue (2020 per books) [5]		187,658,364		
18	Percent Limit		2.50%		
19	Maximum Annual Revenue Requirement Increase		4,691,459		

Notes:
(1) Beginning utility plant corresponds to RevReq-4, Column 7, Line 1
(2) Forecasted plant additions less forecasted 2021 Exeter building additions. See Page 2 Line 3
(3) Beginning accumulated depreciation corresponds to RevReq-4, Column 7, Line 2
(4) Refer to Exhibit KES-2
(5) Revenue for externally supplied customers is adjusted by imputing the Company’s basic service charges

Unitil Energy Systems, Inc.
Docket DE 21-030
Schedule CGDN-2
Page 2 of 3

UNITIL ENERGY SYSTEMS, INC.
FORECASTED PLANT ADDITIONS AND DEPRECIATION
FOR THE YEAR ENDED DECEMBER 31, 20XX

LINE NO.	(1) DESCRIPTION		(2) 2021	(3) 2022	(4) 2023
1	Projected Capital Expenditures		31,586,277	37,526,565	36,977,986
2	Less: Exeter Building Close Out Work [1]		500,000	-	-
3	Net Capital Expenditures		31,086,277	37,526,565	36,977,986
4	Annual Depreciation	3.36%			
5	2020 Depreciation [2]		12,799,754	12,799,754	12,799,754
6	2021 Plant Additions		522,249	1,044,499	1,044,499
7	2022 Plant Additions			630,446	1,260,893
8	2023 Plant Additions				621,230
9	Total		13,322,003	14,474,699	15,726,376

Notes:
(1) Company revenue requirement includes pro forma rate base adjustment for Exeter DOC additions. See Schedule RevReq-4-4
(2) Refer to Schedule RevReq-3-16 P2, Col 9, Line 47

Unitil Energy Systems, Inc.
Docket DE 21-030
Schedule CGDN-2
Page 3 of 3

UNITIL ENERGY SYSTEMS, INC.
PRE-TAX RATE OF RETURN
5 QUARTER AVERAGE ENDED DECEMBER 31, 2020 PRO FORMA

LINE NO.	(1) Description	(2) Amount	(3) Proforma Adjustment	(4) Proformed Amount	(5) Weight	(6) Cost of Capital	(7) Weighted Cost of Capital	(8) Tax Factor	(9) Pre-Tax Cost
1	Common Stock Equity	$ 101,242,877	$ -	$ 101,242,877	52.91%	10.00%	5.29%	1.3714	7.26%
2	Preferred Stock Equity	188,700	-	188,700	0.10%	6.00%	0.01%		0.01%
3	Long Term Debt	93,400,000	(3,500,000)	89,900,000	46.99%	5.49%	2.58%		2.58%
4	Short Term Debt	-	-	-	0.00%	1.68%	0.00%		0.00%
5	Total	$ 194,831,577	$ (3,500,000)	$ 191,331,577	100.00%		7.88%		9.84%

Unitil Energy Systems, Inc.
Docket No. DE 21-030
Schedule CGDN-3
Page 1 of 4

UNITIL ENERGY SYSTEMS, INC.
COMPUTATION OF REVENUE REQUIREMENT FOR TEMPORARY RATES
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO.	(1) DESCRIPTION	(2) REFERENCE		(3) AMOUNT
1	Rate Base	2020 Test Year-End Rate Base	$	223,474,292
2	Rate of Return	Schedule CG-DN-3, Page 2 of 4		7.61%
3	Income Required	Line 1 * Line 2		17,006,394
4	Adjusted Net Operating Income[2]	Schedule CG-DN-3, Page 3 of 4		12,767,903
5	Deficiency	Line 3 - Line 4		4,238,491
6	Income Tax Effect	Line 7 - Line 5		1,574,270
7	Revenue Deficiency for Temporary Rates	1.3714 (Schedule RevReq 1-1) * Line 5	$	5,812,761

UNITIL ENERGY SYSTEMS, INC.
WEIGHTED AVERAGE COST OF CAPITAL
5 QUARTER AVERAGE ENDED DECEMBER 31, 2020 PRO FORMA ROE SET AT CURRENTLY AUTHORIZED

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
LINE NO.	DESCRIPTION	AMOUNT	PROFORMA ADJUSTMENT	PROFORMED AMOUNT	WEIGHT	COST OF CAPITAL	WEIGHTED COST OF CAPITAL	REFERENCE
1	Common Stock Equity	$ 101,242,877	$ -	$ 101,242,877	52.91%	9.50%	5.03%	Amount Currently Authorized
2	Preferred Stock Equity	188,700	-	188,700	0.10%	6.00%	0.01%	Schedule RevReq 5-1 and 5-6
3	Long Term Debt	93,400,000	(3,500,000)	89,900,000	46.99%	5.49%	2.58%	Schedule RevReq 5-1 and 5-4
4	Short Term Debt	-	-	-	0.00%	1.68%	0.00%	Schedule RevReq 5-1 and 5-5
5	Total	$ 194,831,577	$ (3,500,000)	$ 191,331,577	100.00%		7.61%	

UNITIL ENERGY SYSTEMS, INC.
PROPOSED TEMPORARY RATE
INTEREST SYNCRONIZATION

LINE NO.	DESCRIPTION		AMOUNT
1	Per Books Operating Income[1]	$	11,613,315
2	Adjustment for Lost Base Revenue [2]		1,076,981
3	Adjusted Operating Income	$	12,690,296
4	Interest Synchronization		
5	Rate Base	$	223,474,292
6	x Weighted Cost of Debt		2.58%
7	Interest Expense for Ratemaking	$	5,764,650
8	Less: 2020 Book Interest Expense (FERC 427-432) [3]		5,478,066
9	Increase / (Decrease) in Interest Expense	$	286,584
10	Tax-Effect (27.08% * Int. Sync)		(77,607)
11	Adjusted Net Operating Income	$	12,767,903

Notes:
(1) See Schedule RevReq-2 P1, column 4, line 21
(2) Per Docket No. DE 20-092 Exhibit Unitil Attachment L2, Page 1 (Bates Page 953),
Line 3 + Line 7 + Line 11 + Line 14
(3) Excludes interest on customer deposits

UNITIL ENERGY SYSTEMS, INC.
PROPOSED TEMPORARY RATE
EFFECTIVE JUNE 1, 2021

DESCRIPTION		AMOUNT
Temporary Rate Increase	$	5,812,761
Test Year kWh Sales		1,160,418,601
Temporary Rate $/kWh	$	0.00501
$ Impact on a 600 kWh residential bill	$	3.01

UNITIL ENERGY SYSTEMS, INC.
DOCKET DE 21-030
REVENUE REQUIREMENT WORKPAPERS

UNITIL ENERGY SYSTEMS
FT Income Statement - Act by Mechani
R_UES_4_B_FTxM

ELECTRIC FLOWTHRU INCOME STATEMENTS BY MECHANISM
ACTUAL DATA

Workpaper - Flowthrough Detail
For Periods Ending December 31, 2020
Table of Contents

	EE ODR	LIEAP	Co-Gen QF	External Delivery	Stranded Cost	Default Service - Non G1	Default Service - G1	RPS Non G1	RPS G1	RGGI	Storm Recovery	EE BB	Lost Base Rev	Total Flowthru	Total Base	Total Base & Flowthru
OPERATING REVENUES																
Electric Service Revenue:																
Residential (440)	$ 2,690,815	$ (283,407)	$ -	$ 15,005,975	$ (86,685)	$ 36,633,258	$ -	$ 3,310,436	$ -	$ -	$ 434,307	$ -	$ 377,337	$ 58,082,035	$ 31,580,284	$ 89,662,319
Regular General (4421)	1,651,704	475,964	-	9,243,182	(49,753)	11,028,353	-	1,145,666	-	-	266,529	-	231,601	23,993,246	16,910,027	40,903,272
Large General (4422)	1,667,409	479,651	-	9,356,659	(54,721)	-	2,875,933	-	344,074	-	268,605	-	233,787	15,171,397	7,736,414	22,907,810
Public Street Light (444)	39,793	11,272	-	222,330	(1,303)	284,961	-	29,452	-	-	6,542	-	5,754	598,803	1,823,495	2,422,298
Sales to Public Auth (445)	130	37	-	734	(17)	262	-	27	-	-	21	-	18	1,212	6,333	7,545
Sales for Resale (447)	-	-	1,521,144	-	-	-	-	-	-	-	-	-	-	1,521,144	-	1,521,144
Other Sales (449)	533,356	(468,878)	(24,268)	1,430,204	(151,553)	(2,122,134)	147,482	(146,890)	(10,482)	(39,104)	-	(2,285)	(24,068)	(878,620)	280,812	(597,808)
Total Electric Service Revenue	$ 6,583,206	$ 214,640	$ 1,496,876	$ 35,259,083	$ (344,033)	$ 45,824,701	$ 3,023,415	$ 4,338,691	$ 333,592	$ (39,104)	$ 976,004	$ (2,285)	$ 824,430	$ 98,489,216	$ 58,337,364	$ 156,826,580
Other Operating Revenues:																
Late Payment Charges (450)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	94,600	94,600
Misc. Service Revenues (451)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	194,996	194,996
Rent-elect. Property (454)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	585,200	585,200
Other Electric Rev (456)	947,170	-	-	-	-	-	-	-	-	128,893	-	2,285	-	1,078,347	143,733	1,222,080
Total Other Operating Revenues	$ 947,170	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 128,893	$ -	$ 2,285	$ -	$ 1,078,347	$ 1,018,528	$ 2,096,875
TOTAL OPERATING REVENUES	$ 7,530,376	$ 214,640	$ 1,496,876	$ 35,259,083	$ (344,033)	$ 45,824,701	$ 3,023,415	$ 4,338,691	$ 333,592	$ 89,789	$ 976,004	$ -	$ 824,430	$ 99,567,563	$ 59,355,892	$ 158,923,455
OPERATING EXPENSES																
Operation & Maint. Expenses:																
Purchased Power (555-557)	-	-	1,496,876	(1,500,014)	(344,033)	45,346,245	2,969,642	4,427,065	340,488	-	-	-	-	52,736,269	284,252	53,020,521
Transmission (560-579)	-	-	-	35,400,175	-	-	-	-	-	-	-	-	-	35,400,175	68,559	35,468,734
Distribution (580-599)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9,476,199	9,476,199
Cust. Accounting (901-905)	-	-	-	-	-	319,643	2,029	-	-	-	-	-	-	321,671	3,965,244	4,286,916
Cust. Service (907-910)	7,208,391	-	-	-	-	-	-	-	-	89,789	-	-	-	7,298,180	28,775	7,326,955
Admin. & General (920-935)	-	214,640	-	510,513	-	44,888	55,333	-	-	-	-	-	-	825,374	8,925,457	9,750,830
Total O & M Expenses	$ 7,208,391	$ 214,640	$ 1,496,876	$ 34,410,673	$ (344,033)	$ 45,710,776	$ 3,027,003	$ 4,427,065	$ 340,488	$ 89,789	$ -	$ -	$ -	$ 96,581,669	$ 22,748,486	$ 119,330,155
Other Operating Expenses:																
Deprtn. (403)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12,680,791	12,680,791
Amort. (404-407)	-	-	-	83,266	-	-	-	-	-	-	976,004	-	-	1,059,270	2,203,158	3,262,428
Taxes-Other Than Inc. (408)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7,166,678	7,166,678
Income Taxes-Federal (409)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,180,388)	(1,180,388)
State Income Tax (409)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,096,468)	(1,096,468)
Def. Income Taxes (410,411)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,203,294	5,203,294
Total Other Operating Expenses	$ -	$ -	$ -	$ 83,266	$ -	$ -	$ -	$ -	$ -	$ -	$ 976,004	$ -	$ -	$ 1,059,270	$ 24,977,064	$ 26,036,335
TOTAL OPERATING EXPENSES	$ 7,208,391	$ 214,640	$ 1,496,876	$ 34,493,939	$ (344,033)	$ 45,710,776	$ 3,027,003	$ 4,427,065	$ 340,488	$ 89,789	$ 976,004	$ -	$ -	$ 97,640,939	$ 47,725,551	$ 145,366,489
NET UTILITY OPERATING INCOME	$ 321,985	$ -	$ -	$ 765,144	$ -	$ 113,925	$ (3,589)	$ (88,374)	$ (6,896)	$ -	$ -	$ -	$ 824,430	$ 1,926,625	$ 11,630,341	$ 13,556,966
OTHER INCOME & DEDUCTIONS																
Other Income:																
Other (419, 421)	-	-	-	(522,056)	-	(113,925)	3,589	88,374	6,896	-	-	-	-	(537,123)	907,764	370,641
Other Income Deduc. (425, 426)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	272,574	272,574
Income Tax, Other Inc & Ded	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26,560	26,560
Net Other Income & Deductions	$ -	$ -	$ -	$ (522,056)	$ -	$ (113,925)	$ 3,589	$ 88,374	$ 6,896	$ -	$ -	$ -	$ -	$ (537,123)	$ 608,630	$ 71,508
GROSS INCOME	$ 321,985	$ -	$ -	$ 243,087	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 824,430	$ 1,389,502	$ 12,238,971	$ 13,628,474
Interest Charges (427 - 432)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,495,092	5,495,092
NET INCOME	$ 321,985	$ -	$ -	$ 243,087	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 824,430	$ 1,389,502	$ 6,743,880	$ 8,133,382
Less: Pref. Dividend Req.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11,322	11,322
EARN. AVAIL. FOR COMMON STOCI	$ 321,985	$ -	$ -	$ 243,087	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 824,430	$ 1,389,502	$ 6,732,558	$ 8,122,060

UNITIL ENERGY SYSTEMS, INC.
LATE PAYMENT REVENUE ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 1.1
Table of Contents

	(1)	(2)
LINE NO.	DESCRIPTION	TOTAL
1	Normalized Late Payment Revenue(1)	$ 275,537
2	Test Year Late Payment Revenue	94,600
3	Late Payment Revenue Adjustment	$ 180,938

Notes
(1) Normalized Late Payment Revenue based on 2019 calendar year activity

UNITIL ENERGY SYSTEMS, INC.
UNION PAYROLL ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 2.1
Table of Contents

LINE NO.	(1) DESCRIPTION	(2) TOTAL
1	Payroll - Five Months Ended May 31, 2020	$ 1,917,269
2	2020 Salary & Wage Increase[(1)]	3.00%
3	Union Payroll Annualization	$ 57,518

Notes
(1) Average Union increase of 3% effective June 1, 2020

UNITIL ENERGY SYSTEMS, INC.
UNION AND NONUNION PAYROLL/COMPENSATION (1)
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 2.2
Table of Contents

LINE NO.	(1) DESCRIPTION	(2) TOTAL
1	Union Weekly Payroll	$ 4,793,090
2	Total Nonunion Payroll (2)	1,405,138
3	Total Payroll (3)	6,198,228
4	Payroll Capitalization (3)	(3,972,999)
5	Test Year O&M Payroll	$ 2,225,229

Notes
(1) Payroll Allocation to Union and Non-Union based on ADP 2020 Year End Payroll Registers
(2) Includes Incentive Compensation at Target of $104,079
(3) Refer to Workpaper 2.3

UNITIL ENERGY SYSTEMS, INC.
PAYROLL SUMMARY
FOR COMPUTATION OF PAYROLL BENEFIT RELATED OVERHEADS

Workpaper 2.3
Table of Contents

	(1)	(2)
LINE NO.	DESCRIPTION	2020 INCENTIVE COMP AT TARGET
1	O&M PAYROLL:	
2	OPERATIONS	929,656
3	MAINTENANCE	883,050
4	TOTAL O&M PAYROLL	1,812,706
5	CONSTRUCTION PAYROLL:	
6	DIRECT	1,735,013
7	INDIRECT	1,355,228
8	TOTAL CONSTRUCTION PAYROLL	3,090,241
9	OTHER PAYROLL:	
10	CLEARING ACCOUNTS	182,391
11	UNPRODUCTIVE TIME	761,241
12	MOBILE DATA SYSTEMS (MDS)	247,571
13	INCENTIVE COMPENSATION at TARGET	104,079
14	TEMPORARY SERVICES	12,750
15	OTHER (1)	23,411
16	TOTAL OTHER PAYROLL	1,331,442
17	TOTAL PAYROLL	6,234,389
18	O&M PAYROLL:	
19	OPERATIONS	929,656
20	MAINTENANCE	883,050
21	ALLOCATED CLEARING	52,528
22	ALLOCATED UNPRODUCTIVE	114,186
23	ALLOCATED MDS	231,237
24	ALLOCATED INCENTIVE COMPENSATION	14,571
25	TOTAL O&M PAYROLL	2,225,229
26	CONSTRUCTION PAYROLL:	
27	DIRECT	1,735,013
28	INDIRECT	1,355,228
29	ALLOCATED CLEARING	129,862
30	ALLOCATED UNPRODUCTIVE	647,055
31	ALLOCATED MDS	16,334
32	ALLOCATED INCENTIVE COMPENSATION	89,508
33	TOTAL CONSTRUCTION PAYROLL	3,972,999
34	TOTAL PAYROLL, NET OF OTHER PAYROLL	6,198,228
35	TOTAL OTHER PAYROLL:	
36	BELOW THE LINE PAYROLL (2)	12,750
37	OTHER (1)	23,411
38	TOTAL OTHER PAYROLL	36,161
39	TOTAL PAYROLL, WITH INCENTIVE COMP ADJ TO TARGET	6,234,389

UNITIL ENERGY SYSTEMS, INC.
PAYROLL - INCENTIVE COMPENSATION ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 2.4
Table of Contents

LINE NO.	(1) Description		(2) Amount
1	Unitil Energy Services, Inc. Payroll:		
2	Adjustment to reflect Incentive Compensation at Target		
3	Test Year Accrued Incentive Compensation		$ 104,079
4	Incentive Compensation at Target		104,079
5	Test Year Accounting Adjustment to reflect Incentive Compensation at Target		-
6	Capitalized Incentive Compensation at	82.00%	-
7	Test Year Incentive Comp Accounting Adjustment to O&M		-
8	USC Payroll, allocated to Unitil Energy Systems, Inc.:		
9	Adjustment to reflect Incentive Compensation at Target		
10	Test Year Accrued Incentive Compensation at USC		3,412,143
11	Test Year Accrued Incentive Compensation Percentage Billed to UES In 2020	27.50%	938,339
12	Incentive Compensation at Target		938,339
13	Test Year Accounting Adjustment to reflect Incentive Compensation at Target		-
14	Capitalized Incentive Compensation at	28.45%	-
15	Test Year Incentive Comp Accounting Adjustment to O&M		-

UNITIL ENERGY SYSTEMS, INC.
MEDICAL AND DENTAL INSURANCE
FOR THE 12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 3.1
Table of Contents

Line No.	Coverage	Employee Census (1)				2021 Rates (2)				- Cost -				
		- Medical -		- Dental -		- Medical -		- Dental -		- Medical -		- Dental -		
		CDHP	PPO	Plus	Standard	CDHP	PPO	Plus	Standard	CDHP	PPO	Plus	Standard	Total
1	Individual	6	2	6	12	$ 792.45	$ 1,033.07	$ 46.56	$ 45.21	$ 4,755	$ 2,066	$ 279	$ 543	$ 7,643
2	Two Person	10	12	7	18	1,362.76	1,859.73	83.34	80.82	13,628	22,317	583	1,455	37,983
3	Family	8	12	5	23	1,849.91	2,564.50	147.21	141.43	14,799	30,774	736	3,253	49,562
4	Total	24	26	18	53					33,182	55,157	1,599	5,250	95,187
5	2021 Annual Cost Based on Employee Enrollments at December 31, 2020									398,179	661,883	19,185	63,002	1,142,249
6	Employee Contribution (3)									(79,636)	(132,377)	(3,837)	(12,600)	(228,450)
7	Net Cost									318,543	529,506	15,348	50,402	913,799
8	Plus: Company Contribution to HSA									21,000	-	-	-	21,000
9	Payments to Employees to Opt out									9,920	12,830	-	-	22,750
10	Total HSA and Opt out Payments									30,920	12,830	-	-	43,750
11	Proformed 2021 Medical Cost									349,463	542,336	15,348	50,402	957,549
12	Projected Increase in Premium Rates Effective January 1, 2022 (4)									29,562	48,810	614	2,016	81,002
13	Proformed 2021 and 2022 Medical and Dental Cost									379,025	591,147	15,962	52,418	1,038,551
14	Amount Chargeable to Capital (5)									(296,639)	(468,326)	(12,706)	(41,724)	(819,396)
15	Total Pro-formed Medical and Dental Insurance O&M Expense													219,155
16	Less Test Year O&M Expense (6)													95,921
17	Total O&M Medical & Dental Insurance Adjustment													$ 123,234

Notes
(1) Employee Benefit Census as of December 31, 2020
(2) Anthem and Northeast Delta Dental monthly insurance rates, effective January 1, 2021
(3) Employee Contributions: 20%
(4) Estimated increase effective January 1, 2022
Medical Increase 9.00%
Dental Increase 4.00%
(5) Capitalization Rate: 63.68%
(6) Refer to Workpaper 3.2

UNITIL ENERGY SYSTEMS, INC.
MEDICAL INSURANCE
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 3.2
Table of Contents

LINE NO.	(1) Description		(2) Amount
1	Medical Insurance Expense		$ 883,100
2	Benefits Cost Capitalized at	63.68%	(562,358)
3	Subtotal Medical Costs		320,742
4	Employee Contribution		(203,241)
5	Drug Subsidy		(28,556)
6	Subtotal		(231,797)
7	Net Test Year Medical Insurance Expense		88,945
8	Dental Insurance Expense		52,306
9	Benefits Cost Capitalized at	63.68%	(33,308)
10	Subtotal Dental Costs		18,998
11	Employee Contribution		(12,021)
12	Net Test Year Dental Costs		6,976
13	Net Test Year Medical & Dental Costs		$ 95,921

UNITIL ENERGY SYSTEMS, INC.
MEDICAL AND DENTAL INSURANCE - UNITIL SERVICE CORP
FOR THE 12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 3.3
Table of Contents

Line No.	Coverage	Employee Census [1]				2021 Rates [2]				Costs				
		Medical		Dental		Medical		Dental		Medical		Dental		
		CDHP	PPO	Plus	Standard	CDHP	PPO	Plus	Standard	CDHP	PPO	Plus	Standard	Total
1	Individual	80	-	79	48	$ 792.45	$ 1,033.07	$ 46.56	$ 45.21	$ 63,396	$ -	$ 3,678	$ 2,170	$ 69,244
2	Two Person	64	1	77	36	1,362.76	1,859.73	83.34	80.82	87,217	1,860	6,417	2,910	98,403
3	Family	82	1	100	79	1,849.91	2,564.50	147.21	141.43	151,693	2,565	14,721	11,173	180,151
4	Total	226	2	256	163					302,305	4,424	24,816	16,253	347,798
5	2021 Annual Cost Based on Employee Enrollments at December 31, 2020									3,627,663	53,091	297,797	195,031	4,173,582
6	Employee Contribution [3]									(725,533)	(10,618)	(59,559)	(39,006)	(834,716)
7	Net Cost									2,902,130	42,473	238,238	156,025	3,338,865
8	Plus: Company Contribution to HSA									186,000	-	-	-	186,000
9	Payments to Employees to Opt out									178,400	-	-	-	178,400
10	Total HSA and Opt out Payments									364,400	-	-	-	364,400
11	Proformed 2021 Medical Cost									3,266,531	42,473	238,238	156,025	3,703,266
12	Projected Increase in Premium Rates Effective January 1, 2022 [4]									277,248	3,823	9,530	6,241	296,841
13	Proformed 2021 and 2022 Medical and Dental Cost									3,543,778	46,295	247,767	162,266	4,000,106
12	Apportionment to UES at 27.50%									974,539	12,731	68,136	44,623	1,100,029
13	Amount Chargeable to Capital at 29.42%									(286,709)	(3,746)	(20,046)	(13,128)	(323,629)
14	Total Pro-formed Medical and Dental Insurance O&M Expense													776,401
15	Less Test Year O&M Expense [5]													416,480
16	Total O&M Medical & Dental Insurance Adjustment													$ 359,921

Notes
(1) Employee Benefit Census as of December 31, 2020.
(2) Health Plans, Inc. and Northeast Delta Dental monthly insurance rates, effective January 1, 2021.
(3) Employee Contributions: 20%
(4) Estimated increase effective January 1, 2022
Medical Increase 9.00%
Dental Increase 4.00%
(5) Refer to Workpaper 3.4

UNITIL SERVICE CORP.
MEDICAL INSURANCE
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 3.4
Table of Contents

LINE NO.	(1) Description	(2) Medical	(3) Dental	(4) Total
1	Medical Insurance	$ 2,587,331	$ 304,575	$ 2,891,906
2	Employee Contribution	(703,135)	(59,946)	(763,081)
3	Drug Subsidy	(34,106)	-	(34,106)
4	Subtotal	1,850,090	244,629	2,094,719
5	UES Apportionment at	28.17%	28.17%	28.17%
6	Expense Apportioned to UES	521,170	68,912	590,082
7	Capitalization Rate at	29.42%	29.42%	29.42%
8	UES Capitalization	(153,328)	(20,274)	(173,602)
9	Net USC Test Year Medical & Dental Costs Allocated to UES	$ 367,842	$ 48,638	$ 416,480

Unitil Energy Systems, Inc.
Pension Expense
2020 Actual Expense Recorded and 2021 Forecast Expense

Workpaper 4.1
Table of Contents

LINE NO.	(1) Description	(2) 2020 TEST YEAR	(3) 2021 FORECAST EXPENSE	(4) PROFORMA ADJUSTMENT
A1	USC Labor & Overhead Charged to UES	28.17%	28.17%	
A2	UES Capitalization Rates	63.68%	63.68%	
A3	USC Labor & Overhead to Construction	29.42%	29.42%	
A4	Total USC Pension Expense per Actuary	$ 3,032,609	$ 3,232,617	
	Calculation of Pension Expense, net of amounts chargeable to capital			
	A. UES Pension Expense, net:			
1	UES Pension Expense per Actuary	$ 1,258,030	$ 1,320,039	$ 62,009
2	Less: Amounts chargeable to capital	(801,114)	(840,601)	(39,487)
3	Total UES Pension Expense, net	$ 456,916	$ 479,438	$ 22,522
	B. Unitil Service Pension Expense allocated to UES, net:			
4	Unitil Service Pension Expense per Actuary	$ 854,286	$ 910,628	$ 56,342
5	Less: Amounts chargeable to capital	(251,331)	(267,907)	(16,576)
6	Unitil Service Pension Expense allocated to UES, net	$ 602,955	$ 642,721	$ 39,766
7	Total UES Pension Expense	$ 1,059,872	$ 1,122,160	$ 62,288

Unitil Energy Systems, Inc.
PBOP Expense
2020 Actual Expense Recorded and 2021 Forecast Expense

Workpaper 4.2
Table of Contents

LINE NO.	(1) Description	(2) 2020 TEST YEAR	(3) 2021 FORECAST EXPENSE	(4) PROFORMA ADJUSTMENT
A1	USC Labor & Overhead Charged to UES	28.17%	28.17%	
A2	UES Capitalization Rates	63.68%	63.68%	
A3	USC Labor & Overhead to Construction	29.42%	29.42%	
A4	Total USC PBOP Expense per Actuary	$ 1,510,206	$ 1,358,914	
	Calculation of PBOP Expense, net of amounts chargeable to capital			
	A. UES PBOP Expense, net:			
1	UES PBOP Expense per Actuary	$ 1,626,222	$ 1,594,405	$ (31,817)
2	Less: Amounts chargeable to capital	(1,035,578)	(1,015,317)	20,261
3	Total UES PBOP Expense, net	$ 590,644	$ 579,088	$ (11,556)
	B. Unitil Service PBOP Expense allocated to UES, net:			
4	Unitil Service PBOP Expense per Actuary	$ 425,425	$ 382,806	$ (42,619)
5	Less: Amounts chargeable to capital	(125,160)	(112,622)	12,538
6	Unitil Service PBOP Expense Allocated to UES, net	$ 300,265	$ 270,185	$ (30,080)
7	Total UES PBOP Expense	$ 890,909	$ 849,272	$ (41,636)

Unitil Energy Systems, Inc.
SERP Expense
2020 Actual Expense Recorded and 2021 Forecast Expense

Workpaper 4.3
Table of Contents

LINE NO.	(1) DESCRIPTION	(2) 2020 TEST YEAR	(3) 2021 EXPENSE	(4) PROFORMA ADJUSTMENT
A1	USC Labor & Overhead Charged to UES	28.17%	28.17%	
A2	UES Capitalization Rates	63.68%	63.68%	
A3	USC Labor & Overhead to Construction	29.42%	29.42%	
A4	Total USC SERP Expense per Actuary	$ 1,924,767	$ 2,357,253	
	Calculation of SERP Expense, net of Amounts Chargeable to Construction			
	A. UES SERP Expense, net:			
1	UES SERP Expense	$ -	$ -	$ -
2	Less: Amounts chargeable to construction	-	-	-
3	UES SERP Expense, net	$ -	$ -	$ -
	B. Unitil Service SERP Expense Allocated to UES, net:			
4	Unitil Service SERP Expense	$ 542,207	$ 664,038	$ 121,831
5	Less: Amounts chargeable to construction	(159,517)	(195,360)	(35,843)
6	Unitil Service SERP Expense Allocated to UES, net	$ 382,690	$ 468,678	$ 85,989
7	Total UES SERP Expense	$ 382,690	$ 468,678	$ 85,989

Unitil Energy Systems, Inc.
401K Expense
2020 Actual Expense Recorded and 2021 & 2022 Forecast Expense

Workpaper 4.4
Table of Contents

Line No.	(1) Description	(2) 2020 TEST YEAR	(3) 2021 & 2022 FORECAST EXPENSE	(4) PROFORMA ADJUSTMENT
A1	USC Labor & Overhead Charged to UES	28.17%	28.17%	
A2	UES Capitalization Rates	63.68%	63.68%	
A3	USC Labor & Overhead to Construction	29.42%	29.42%	
A4	Total USC 401K Expense (1)	$ 1,994,120	$ 2,081,861	
	Calculation of 401K Expense, net of Amounts Chargeable to Capital			
	A. UES 401K Expense, net:			
1	UES 401K Expense 2021 Proformed (2)	$ 266,172	$ 274,557	$ 8,385
2	UES 401K Expense adjusted for 2022 wage increase	-	8,649	8,649
3	Total UES 401K Expense - Proformed	266,172	283,206	17,034
4	Less: Amounts chargeable to capital	(169,498)	(180,346)	(10,847)
5	Total UES 401K Expense, net	$ 96,674	$ 102,860	$ 6,187
	B. Unitil Service 401K Expense allocated to UES, net:			
6	Unitil Service 401K Expense 2021 Proformed	$ 561,744	$ 586,460	$ 24,717
7	Unitil Service 401K Adjusted for 2022 Wage Increase(1)	-	25,804	25,804
8	Total USC 401K Expense - Proformed	561,744	612,264	50,521
9	Less: Amounts chargeable to capital	(165,265)	(180,128)	(14,863)
10	Unitil Service 401K Expense Allocated to UES, net	$ 396,479	$ 432,136	$ 35,658
11	Total UES 401K Expense	$ 493,152	$ 534,997	$ 41,844

Notes
(1) Unitil Service Corp. - Average 2020/2021 Payroll Increase of 4.40%
(2) See Workpaper 4.5

Unitil Energy Systems, Inc.
401K Adjustment
2020 & 2021 Weighted Average Pay Increase

Workpaper 4.5
Table of Contents

	(1)	(2)	(3)	(4)	(5)	(6)
LINE NO.	DESCRIPTION	2020 ANNUALIZED PAYROLL	2021 AVERAGE PAY INCREASE(1)	WEIGHTED AVERAGE INCREASE	2022 AVERAGE PAY INCREASE(2)	WEIGHTED AVERAGE INCREASE
1	Nonunion	$ 1,405,138	3.65%	0.82%	3.65%	0.82%
2	Union	$ 4,850,608	3.00%	2.33%	3.00%	2.33%
3	Total	$ 6,255,746		3.15%		3.15%

Notes
(1) Refer to Schedule RevReq-3-2, Page 1 of 2 for 2021 Payroll Increases
(2) Refer to Schedule RevReq-3-2, Page 1 of 2 for 2022 Payroll Increase

Unitil Energy Systems, Inc.
Deferred Compensation Plan Expense
2020 Actual Expense Recorded and 2021 & 2022 Forecast Expense

Workpaper 4.6
Table of Contents

	(1)	(2)	(3)	(4)
Line No.	Description	2020 TEST YEAR	2021 & 2022 FORECAST EXPENSE	PROFORMA ADJUSTMENT
A1	USC Labor & Overhead Charged to UES	28.17%	28.17%	
A2	UES Capitalization Rates	63.68%	63.68%	
A3	USC Labor & Overhead to Construction	29.42%	29.42%	
A4	Total USC Eligible Base Compensation	$ 369,511	$ 2,802,136	
A5	Total USC Eligible Incentive Compensation (at target)	$ 241,091	$ 952,203	
	Calculation of Deferred Compensation Expense, net of Amounts Chargeable to Construction			
	A. UES Deferred Compensation Expense, net:			
1	UES Deferred Comp Expense 2021 Proformed	$ -	$ -	$ -
2	UES Deferred Comp Expense adjusted for 2022 wage increase	-	-	-
3	Total UES Deferred Comp Expense - Proformed	-	-	-
4	Less: Amounts chargeable to capital	-	-	-
5	Total UES Deferred Comp Expense, net	$ -	$ -	$ -
	B. Unitil Service Deferred Comp Expense allocated to UES, net:			
6	Unitil Service 2020 Deferred Comp. Expense	$ 36,951	$ 280,214	$ 243,263
7	Unitil Service Deferred Comp Expense Allocated to UES	10,409	78,936	68,527
8	Unitil Service Deferred Incentive Compensation Expense	24,109	95,220	71,111
9	Unitil Service Deferred Incentive Compensation Expense Allocated to UES	6,792	26,824	20,032
10	Unitil Service Deferred Comp. Adjusted for 2021 Wage Increase[1]	-	3,473	3,473
11	Total Unitil Service Deferred Comp Expense Allocated to UES - Proformed	17,201	109,233	92,032
12	Less: Amounts Chargeable to Construction	(5,061)	(32,136)	(27,075)
13	Unitil Service Deferred Comp Expense Allocated to UES, net	$ 12,140	$ 77,097	$ 64,957
14	Total UES Deferred Comp Expense	$ 12,140	$ 77,097	$ 64,957

Notes
(1) Unitil Service Corp - Estimated 2020 Average Payroll Increase of 4.40%

UNITIL ENERGY SYSTEMS, INC.
PROPERTY AND LIABILITY INSURANCES ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 5.1
Table of Contents

LINE NO.	DESCRIPTION	AMOUNT [1]
	Current Coverage Periods	
	Property:	
1	All Risk	$ 111,753
2	Crime	2,374
3	K&E	325
4	Total Property	$ 114,452
	Liability:	
5	Workers' Compensation	$ 61,293
6	Excess	435,017
7	Automobile	37,164
8	Directors & Officers	74,047
9	Cyber	21,919
10	Fiduciary	7,253
11	Total Liability	$ 636,692
12	Total Property & Liability Insurances (Lines 4 Plus 11)	751,145
13	Less: Amounts Chargeable to Capital	422,627
14	Amount to O&M Expense	328,517
15	Less Test Year O&M Expense	273,026
16	O&M Property and Liability Insurance Increase	$ 55,491

NOTES
(1) See Workpaper W5.3

UNITIL ENERGY SYSTEMS, INC.
PROPERTY AND LIABILITY INSURANCES ADJUSTMENT
12 MONTHS ENDED DECEMBER 31, 2015

Workpaper 5.2
Table of Contents

LINE NO.	DESCRIPTION	UNITIL SERVICE CORP. TOTAL[1]	AMOUNT TO UES	UES TOTAL
	USC Cost For Current Coverage Periods			
	Property:			
1	All Risk	$ 8,805		$ 2,421
2	Crime	682		188
3	K&E	130		36
4	Total Property	$ 9,617	27.50%	$ 2,645
	Liability:			
5	Workers' Compensation	$ 59,336		$ 16,317
6	Excess	108,060		29,717
7	Automobile	8,401		2,310
8	Directors and Officers	19,925		5,479
9	Cyber	5,898		1,622
10	Fiduciary	1,952		537
11	Total Liability	$ 203,573	27.50%	$ 55,982
12	Total USC Property & Liability Insurances			58,627
13	Less Amount Chargeable to Capital		29.42%	17,248
14	Total Property & Liability Insurances to O&M Expense			41,379
15	Less Test Year O&M Expense			24,402
16	O&M Property and Liability Insurance Increase			$ 16,977

NOTES
(1) See Workpaper W5.3

Casualty & Property Insurance

Workpaper 5.3
Table of Contents

		CASUALTY											PROPERTY					
		AL (prem)	NH-WC (prem)	XL* (prem)	XL (brkr) [3]	XL Surplus Tax	Cyber (prem)	FL (prem)	D&O (prem)	D&O Surplus Tax	D&O (brkr) [3]	CASUALTY TOTAL	ARP (prem) [4]	CRIME (prem)	K&E (prem)	TRANSIT (prem) [4]	TOTAL PROP	TOTAL
UES	2018a	25,546	91,767	303,454	9,321	9,104	10,984	4,414	44,258	1,328	5,604	505,780	64,987	1,861	341	5,267	72,455	578,235
	2019a	24,522	93,044	333,707	10,793	10,011	10,649	4,731	43,719	1,333	5,546	538,057	69,166	1,834	325	7,813	79,137	617,194
	2020a	27,110	76,716	353,388	16,498	10,602	12,963	4,731	52,871	1,586	-	556,465	84,960	1,882	325	-	87,167	643,632
	2021a/b[1]	35,225	58,096	384,418	16,375	11,533	21,919	7,253	72,413	1,634	-	608,864	111,753	2,374	325	-	114,452	723,317
	2022e[2]	37,164	61,293	405,574	17,276	12,167						636,692					114,452	751,145
USC	2018a	5,933	97,653	123,302	3,787	3,699	3,948	1,794	17,983	540	2,277	260,917	5,399	756	116		6,270	267,187
	2019a	8,029	92,581	133,432	4,316	4,003	4,327	1,892	17,481	533	2,218	268,811	5,581	733	130		6,444	275,255
	2020a	7,120	85,858	95,093	4,439	2,853	3,488	1,892	14,227	427	-	215,397	6,489	506	130		7,125	222,522
	2021a/b[1]	9,206	65,019	110,396	4,702	3,312	5,898	1,952	19,486	440	-	220,410	8,805	682	130		9,617	230,026
	2022e[2]	8,401	59,336	100,747	4,291	3,022						203,573					9,617	213,189

NOTES

(1) 2021 premiums reflect actuals for automobile, workers compensation, excess liability, cyber, crime, K&E and transit
2021 premiums reflect budgeted amounts for fiduciary, directors & officers and all risk property and will be updated with actuals

(2) 2022 premiums reflect annual growth rate from 2018 to 2020 for UES and USC automobile, workers compensation and excess liability
2022 premiums for these three categories above will be updated with actuals while all other categories assume 2021 premium amounts

(3) In 2020 the Company changed brokers and now the D&O broker fee is included in the XL broker fee

(4) In 2020 the Company changed brokers and now the transit premium is included in the all risk property premium

UNITIL SERVICE CORP.
PROPERTY & LIABILITY INSURANCE TEST YEAR COSTS
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 5.4
Table of Contents

DESCRIPTION	TOTAL
USC O&M Test Year	
12-30-08-00-9240100 PROPERTY INSURANCE	$ 5,519
12-30-08-00-9250100 INJURIES & DAMAGES	120,204
Total	$ 125,723
UES Apportionment	27.50%
UES Amount	$ 34,574
Capitalization Rate	29.42%
Capitalization Amount	$ 10,172
O&M Expense Amount	24,402

UES - OPERATING FACILITY
COMPUTATION OF BUILDING OVERHEAD
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 5.5
Table of Contents

SQUARE FOOTAGE OF SERVICE CENTER UPDATED:		Dec-20	ALLOCATION OF SERVICE CENTER
DESCRIPTION	SQ FT	%	OVERHEADS
SERVICE CENTER ALLOCATED:			
General Area Capitalized (184.00.00)	25,919	31.02%	8,595
			63.68%
			5,473
Stock Area Capitalized (163.00.00)	19,127	22.89%	6,343
			90.00%
			5,709
Garage Area Capitalized:			
Auto-184.01.00	0	0.00%	0
Light Truck-184.02.00	20,273	24.27%	6,723
Heavy Truck-184.03.00	9,282	11.11%	3,078
Sub-Total Garage Area	29,555	35.38%	9,801
Ratio of Garage Area Capitalized			63.68%
Garage Area Capitalized			6,241
Total Service Center to DOC	74,601	89.29%	
			17,423
Non-DOC Space:			JE782
Exclude: none	8,946	10.71%	924.00.01
TOTAL SERVICE CENTER	83,547	100.00%	

(b) DETERMINATION OF SERVICE CENTER PROPERTY INSURANCE:	
BUDGETED ALL RISK PROPERTY INSURANCE	88,470
RATIO OF SERVICE CENTER TO TOTAL PROPERTY	31.32%
TOTAL SERVICE CENTER PROPERTY INSURANCE	27,705
Service Center Property Insurance Capitalization Ratio	62.89%

	ASSET RPT 1025. Accts 101 & 106 12/31/20		
	SERVICE CENTER	ALL STRUCTURE	SERVICE RATIO
STRUCTURES - DISTRIBUTION ACCT. 361		2,173,616	
STRUCTURES-ADMIN ACCT. 390	19,114,262	19,114,262	
GENERAL PLANT - (TOTAL LESS COMM. EQ) (ACCT. 391,393,394,395,398)	4,861,899	4,861,899	
DISTR. PLANT - STATION (362)		50,412,132	
TOTAL COST	23,976,161	76,561,909	31.32%

VEHICLE CLEARING ACCOUNT
TOTAL CHARGES & TOTAL CLEARINGS TO EXPENSE & CAPITAL
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 5.6
Table of Contents

Total Clearings from Clearing Account:

	Expense	Capital	UES Total GL	Total Sch 12	Variance
Jan-20	49,152	52,974	102,125	102,125	-
Feb-20	36,457	42,705	79,162	79,162	-
Mar-20	38,294	36,396	74,690	74,690	-
Apr-20	78,350	61,901	140,251	140,251	-
May-20	55,237	51,110	106,347	106,347	-
Jun-20	54,669	46,389	101,058	101,058	-
Jul-20	54,380	80,659	135,039	135,039	-
Aug-20	58,668	63,409	122,077	122,077	-
Sep-20	41,817	53,338	95,155	95,155	-
Oct-20	27,614	37,600	65,213	65,213	-
Nov-20	16,131	29,010	45,142	45,142	-
Dec-20	83,871	21,875	105,746	105,746	-
	594,638	577,366	1,172,004	1,172,004	
Capitalization Rate		49.26%			

VEHICLE CLEARING ACCOUNT
AUTO LIABILITY INSURANCE

Auto Liability Insurance Payments into Clearing Account (1)	
Jan-20	2,711
Feb-20	2,711
Mar-20	2,711
Apr-20	2,711
May-20	2,711
Jun-20	2,711
Jul-20	2,711
Aug-20	
Sep-20	
Oct-20	
Nov-20	7,045
Dec-20	3,523
Total	29,545

(1) Payments during test year (Jan-Jul) were for 2019-2020 coverage year 10/1/19-9/30/20
Payments in November & December 2020 are for 10/1/20 - 9/30/21 coverage year

Auto Liability Insurance Expense through Clearing Account

	UES
Gross Amount	29,545
Cap. Rates	49.26%
Cap. Amount	14,555
O&M Amount	14,990

UNITIL ENERGY SYSTEMS, INC.
INFLATION ALLOWANCE
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 6.1
Table of Contents

Source: Energy Information Administration
Short-Term Energy Outlook
Publication Date: February 9, 2021

Table 1. U.S. Energy Markets Summary

	2019												2020											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Macroeconomic																								
Real Gross Domestic Product (billion chained 2012 dollars - SAAR)	18,915	18,953	18,984	18,990	19,019	19,053	19,103	19,142	19,180	19,269	19,267	19,226	19,309	19,065	18,658	17,427	17,191	17,289	17,720	18,485	19,584	18,688	18,728	18,763
Percent change from prior year	2.3	2.3	2.2	2	1.9	1.9	2	2.1	2.1	2.6	2.4	2	2.1	0.6	-1.7	-8.2	-9.6	-9.3	-7.2	-3.4	2.1	-3	-2.8	-2.4
GDP Implicit Price Deflator (Index, 2012=100)	111.3	111.5	111.7	112.0	112.2	112.4	112.5	112.6	112.7	112.9	113.0	113.1	113.4	113.4	113.3	112.8	112.8	113.0	113.3	113.8	114.4	114.2	114.3	114.4
Percent change from prior year	2.1	2.0	1.9	1.9	1.8	1.8	1.8	1.7	1.7	1.7	1.6	1.6	1.8	1.7	1.5	0.7	0.5	0.5	0.7	1.0	1.5	1.2	1.2	1.2
Real Disposable Personal Income (billion chained 2012 dollars - SAAR)	14,841	14,864	14,856	14,817	14,810	14,827	14,840	14,912	14,934	14,936	14,997	14,960	15,070	15,163	14,949	17,287	16,454	16,150	16,237	15,693	15,786	15,665	15,467	15,588
Percent change from prior year	3.5	3.4	2.9	2.4	2.0	1.9	1.6	1.8	2.0	1.8	2.1	0.8	1.5	2.0	0.6	16.7	11.1	8.9	9.4	5.2	5.7	4.9	3.1	4.2
Manufacturing Production Index (Index, 2012=100)	106.9	106.3	106.3	105.4	105.5	106.1	105.7	106.4	105.7	105.1	106.1	106.4	106.2	106.1	100.8	84.8	88.1	95.0	99.0	100.4	100.4	101.7	102.6	103.6
Percent change from prior year	2.7	1.1	1	-0.4	0.5	0.3	-0.5	-0.3	-1	-1.5	-0.7	-1.1	-0.7	-0.2	-5.2	-19.5	-16.5	-10.5	-6.3	-5.6	-5	-3.2	-3.3	-2.6
Weather																								
U.S. Heating Degree-Days	859	719	632	288	158	34	5	10	41	254	589	715	740	652	484	358	156	25	5	7	58	247	422	748
U.S. Cooling Degree-Days	9	18	18	42	130	227	373	336	243	75	16	14	15	13	43	43	106	248	398	356	181	83	32	7

	2021												2022											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Macroeconomic																								
Real Gross Domestic Product (billion chained 2012 dollars - SAAR)	18,781	18,818	18,861	18,902	18,963	19,036	19,141	19,222	19,300	19,370	19,444	19,517	19,593	19,662	19,727	19,790	19,849	19,904	19,955	20,004	20,050	20,091	20,134	20,177
Percent change from prior year	-2.7	-1.3	1.1	8.5	10.3	10.1	8	4	-1.4	3.6	3.8	4	4.3	4.5	4.6	4.7	4.7	4.6	4.3	4.1	3.9	3.7	3.5	3.4
GDP Implicit Price Deflator (Index, 2012=100)	114.5	114.6	114.8	115.0	115.1	115.3	115.5	115.6	115.8	116.0	116.2	116.3	116.5	116.6	116.8	117.1	117.3	117.5	117.7	118.0	118.2	118.4	118.6	118.8
Percent change from prior year	1	1.1	1.3	1.9	2.1	2.1	1.9	1.6	1.2	1.6	1.6	1.6	1.7	1.8	1.8	1.8	1.9	1.9	2	2	2.1	2.1	2.1	2.1
Real Disposable Personal Income (billion chained 2012 dollars - SAAR)	16,277	16,371	16,286	15,683	15,499	15,391	15,455	15,433	15,419	15,405	15,413	15,437	15,502	15,533	15,559	15,569	15,591	15,615	15,644	15,669	15,695	15,711	15,742	15,778
Percent change from prior year	8	8	8.9	-9.3	-5.8	-4.7	-4.8	-1.7	-2.3	-1.7	-0.3	-1	-4.8	-5.1	-4.5	-0.7	0.6	1.5	1.2	1.5	1.8	2	2.1	2.2
Manufacturing Production Index (Index, 2012=100)	103.8	104.2	104.4	104.1	104.2	104.4	104.6	104.9	105.2	105.6	106.0	106.5	107.0	107.5	107.9	108.4	108.8	109.1	109.4	109.6	109.9	110.1	110.3	110.5
Percent change from prior year	-2.2	-1.8	3.5	22.7	18.3	9.9	5.6	4.5	4.8	3.8	3.3	2.8	3.1	3.2	3.4	4.1	4.4	4.6	4.6	4.5	4.5	4.2	4	3.8
Weather																								
U.S. Heating Degree-Days	785	679	550	308	134	28	7	10	53	239	485	769	848	684	558	314	134	28	7	10	53	239	485	769
U.S. Cooling Degree-Days	6	12	24	43	127	247	359	333	183	68	22	11	11	12	23	40	127	247	359	333	184	68	22	11

Notes:
The approximate break between historical and forecast values is shown with estimates and forecasts in italics.

Inflation Adjustment
Test Year USC Amortizations

Workpaper 6.2
Table of Contents

		2020
12-30-10-00-404-03-00 SOFTWARE AMORT - OTHER	$	343,313
12-30-10-00-404-04-00 FINANCIAL REPORT WRITER AMORTIZATION		7,350
12-30-10-00-404-23-00 POWER TAX SYSTEM AMORT		30,284
12-30-10-00-404-25-00 AMORTIZATION - PAYMENT SYSTEM		1,492
Total	$	382,438
UES Allocation		28.17%
Amount Billed to UES		107,733

Inflation Adjustment
Test Year Facility Leases

Workpaper 6.3
Table of Contents

		2020
12-30-10-00-9310100 BUILDING RENT	$	1,252,284
12-30-10-00-9310700 CALL CENTER RENT		158,796
12-30-10-00-9310800 PORTSMOUTH RENT EXPENSE		203,988
Total	$	1,615,068
UES Allocation		28.17%
Amount Billed to UES		454,965

UNITIL ENERGY SYSTEMS, INC.
TEST YEAR AMORTIZATION EXPENSE
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 7.1
Table of Contents

	(1)	(2)	(3)	(4)
LINE NO.	DESCRIPTION	BEGINNING UNAMORTIZED BALANCE 2020[1]	2020 AMORTIZATION EXPENSE	ENDING UNAMORTIZED BALANCE 2020
1	Unitil Energy Systems 303-Intangible Plant:			
2	2014 Web Map Improvements	$ 45	$ 45	$ -
3	Enhance critical financial systems	1,453	1,453	-
4	Desktop Client Mgmt	148	148	-
5	2014 Gen Software Enhancements	311	311	-
6	EETS Enhancements 2014	114	114	-
7	Electric Inspections	10,429	10,429	-
8	Milsoft IVR Upgrade	322	322	-
9	MV90xi Upgrade from 2.0 SP1 tp 5.0	4,517	4,517	-
10	2015 IT Infrastructure	11,310	8,482	2,827
11	303-00/ 1/2 : Intangible Software 5 yr	1,936	1,162	774
12	Municipal Maps & Reports	10,557	6,334	4,223
13	MV-90 xi TCIP Network Function/Lisc	3,833	2,300	1,533
14	First Responder - iRestore	48,180	24,090	24,090
15	Enhancements for Third Party Attach	7,083	3,400	3,683
16	Electric Inspections	17,661	7,849	9,812
17	General Software Enhancements	5,036	2,238	2,798
18	2015 Cyber Security Enhancements11	172	76	95
19	2016 IT Infrastructure	28,173	12,521	15,652
20	GPS OMS - Interface	1,553	690	863
21	2016 Cyber Security Enhancements	264	118	147
22	Unify Workforce Management System	7,418	3,297	4,121
23	General Software Enhancements	4,170	1,853	2,317
24	DPU ORP System	10,868	4,830	6,038
25	303-00/ 1/2 : Intangible Software 5 yr	68,677	23,546	45,130
26	EETS Enhancements	19,346	6,633	12,713
27	303-00/ 1/2 : Intangible Software 5 yr	2,525	842	1,683
28	24 Hr Damage Assess. & Field Rest.	43,631	13,425	30,206
29	2017 Cyber Security	2,366	710	1,656
30	2017 IT Infrastructure	10,374	3,112	7,262
31	Electronic Time Sheet Phase One	6,275	1,793	4,482
32	Eintake Migration	20,026	5,589	14,437
33	AMI Command Center Version Upgrade	7,422	1,936	5,486
34	Meter Data Archiving Plan	2,871	749	2,122
35	Upgrade OMS Webpage	5,390	1,320	4,070
36	Powerplan Updated License	72,023	17,638	54,385
37	303-00/ 1/2 : Intangible Software 5 yr	73,752	19,240	54,513
38	IS Project Tracker Replacement	6,999	1,826	5,173
39	Legacy Interface Job Rewrite	3,765	941	2,824
40	General Software Enhancements - 2018	16,888	4,222	12,666
41	UPS Reporting	971	228	742
42	Reset In Service Date	N/A	(11,313)	N/A
43	2018 IT Infrastructure	38,777	9,665	20,119
44	2018 Cyber Security Enhancements	5,491	1,432	4,058
45	WebOps Replacements - Year 1 of 3	15,895	3,974	11,921
46	Dev/ Staging Refresh	9,380	1,908	7,472
47	OMS Regulatory Reports	6,459	1,314	5,146
48	Microsoft Exchange Upgrade	4,279	870	3,409
49	Electronic Time Sheet Phase 2	23,922	4,865	19,056
50	Metersense Upgrade 4.2 to 4.3	491	100	391
51	FCS Upgrade	971	198	774
52	Power Plant Assets	44,323	18,996	25,327
53	Power Plant Assets	30,339	13,002	17,336
54	OMS ABB Purchase	296,165	101,542	194,623
55	OMS Integration & Implementation	184,760	63,346	121,414
56	OMS Osmose Field Survey	66,874	22,928	43,946
57	OMS Internal Labor	8,264	2,833	5,431
58	Power Plant Asset Upgrade	31,634	8,077	23,558
59	Meter Data Management	1,898,800	239,848	1,658,951
60	TESS Replacement	7,023	759	6,264
61	FCS Upgrade	10,361	889	9,472
62	2019 General Software Enhancements	18,921	3,808	14,851
63	WebOps Replacement - Year 2 of 3	21,675	4,146	17,190
64	Reporting Blanket	35,245	6,877	27,832
65	2019 Infrastructure PC & Network	314,152	62,386	246,600
66	Regulatory Work Blanket	8,972	1,078	7,860
67	GIS Overlay Electronic Inspection	19,040	3,808	14,915
68	OMS Upgrade to V9.	4,457	371	4,086
69	GIS Enhancements	6,520	543	5,977
70	Generator Interconnection Database	49,881	10,086	38,961
71	2019 Voice System Replacement	383,511	38,479	341,805
72	2019 Interface Enhancements	21,083	2,065	18,850
73	2019 Customer Facing Enhancements	371,975	37,455	331,506
74	303-00/ 1/2 : Intangible Software 5 yr	17,338	3,468	9,536
75	E-intake Functionality to GEM	28,776	480	28,297
76	EE Tracking & Reporting Syst	81,190	1,353	79,837
77	MV90xi Upgrade v4.5 to 6.0	15,326	255	15,071
78	Replace MV-90 Communication Bank Modules	5,172	922	4,194
79	AMI Command Center Upgrade	37,259	621	36,638
80	Metersense Upgrade 2020	557	9	548
81	Reporting Blanket	37,767	629	37,137
82	Cyber Security Enhancements	36,913	615	36,298
83	Power Plan Upgrade	111,894	1,865	110,029
84	2020 IT Infrastructure Budget	492,478	8,208	484,270
85	2020 Customer Facing Enhancements	232,051	3,868	228,183
86	2020 Interface Enhancements	50,185	836	49,349
87	2020 General Software Enhancements	1,488	25	1,463
88	2017 CIS Amortization	9,199,227	512,318	8,686,909
89	Total UES Amortization Expense for Account 303	$ 14,826,115	$ 1,392,138	$ 13,395,382

NOTES
(1) Projects Installed in 2020 Reflect Total Project Cost

UNITIL ENERGY SYSTEMS, INC.
RATE YEAR AMORTIZATION EXPENSE

Workpaper 7.2
Table of Contents

LINE NO.	(1) DESCRIPTION	(2) TOTAL PROJECT COST	(3) ANNUAL AMORTIZATION EXPENSE
1	Unitil Energy Systems 303-Intangible Plant:		
2	First Responder - iRestore	120,450	24,090
3	Enhancements for Third Party Attach	17,000	3,400
4	Electric Inspections	39,247	7,849
5	General Software Enhancements	11,191	2,238
6	2015 Cyber Security Enhancements11	381	76
7	2016 IT Infrastructure	62,607	12,522
8	GPS OMS - Interface	3,450	690
9	2016 Cyber Security Enhancements	588	118
10	Unify Workforce Management System	16,484	3,297
11	General Software Enhancements	9,266	1,853
12	DPU ORP System	24,150	4,830
13	303-00/ 1/2 : Intangible Software 5 yr	117,732	23,546
14	EETS Enhancements	33,165	6,633
15	303-00/ 1/2 : Intangible Software 5 yr	4,207	841
16	24 Hr Damage Assess. & Field Rest.	67,124	13,425
17	2017 Cyber Security	3,549	710
18	2017 IT Infrastructure	15,561	3,112
19	Electronic Time Sheet Phase One	8,964	1,793
20	Eintake Migration	27,943	5,589
21	AMI Command Center Version Upgrade	9,681	1,936
22	Meter Data Archiving Plan	3,744	749
23	Upgrade OMS Webpage	6,600	1,320
24	Powerplan Updated License	88,191	17,638
25	303-00/ 1/2 : Intangible Software 5 yr	96,044	19,240
26	IS Project Tracker Replacement	9,129	1,826
27	Legacy Interface Job Rewrite	4,775	941
28	General Software Enhancements - 2018	22,077	4,222
29	UPS Reporting	1,142	228
30	2018 IT Infrastructure	49,114	9,665
31	2018 Cyber Security Enhancements	7,175	1,432
32	WebOps Replacements - Year 1 of 3	22,788	3,974
33	Dev/ Staging Refresh	9,539	1,908
34	OMS Regulatory Reports	6,569	1,314
35	Microsoft Exchange Upgrade	4,352	870
36	Electronic Time Sheet Phase 2	24,327	4,865
37	Metersense Upgrade 4.2 to 4.3	499	100
38	FCS Upgrade	985	198
39	Power Plant Assets	189,956	18,996
40	Power Plant Assets	130,023	13,002
41	OMS ABB Purchase	1,015,424	101,542
42	OMS Integration & Implementation	633,462	63,346
43	OMS Osmose Field Survey	229,282	22,928
44	OMS Internal Labor	28,334	2,833
45	Power Plant Asset Upgrade	80,769	8,077
46	Meter Data Management	2,398,484	239,848
47	TESS Replacement	7,593	759
48	FCS Upgrade	10,361	2,320
49	2019 General Software Enhancements	18,921	3,637
50	WebOps Replacement - Year 2 of 3	21,675	4,126
51	Reporting Blanket	35,245	6,680
52	2019 Infrastructure PC & Network	314,152	60,392
53	Regulatory Work Blanket	8,972	2,007
54	GIS Overlay Electronic Inspection	19,040	3,808
55	OMS Upgrade to V9.	4,457	891
56	GIS Enhancements	6,520	1,304
57	Generator Interconnection Database	49,881	9,948
58	2019 Voice System Replacement	383,511	37,630
59	2019 Interface Enhancements	21,083	2,114
60	2019 Customer Facing Enhancements	371,975	37,178
61	303-00/ 1/2 : Intangible Software 5 yr	17,338	3,468
62	E-intake Functionality to GEM	28,776	5,755
63	EE Tracking & Reporting Syst	81,190	16,238
64	MV90xi Upgrade v4.5 to 6.0	15,326	3,065
65	Replace MV-90 Communication Bank Modules	5,172	11,735
66	AMI Command Center Upgrade	37,259	7,452
67	Metersense Upgrade 2020	557	111
68	Reporting Blanket	37,767	7,553
69	Cyber Security Enhancements	36,913	7,383
70	Power Plan Upgrade	111,894	22,379
71	2020 IT Infrastructure Budget	492,478	98,496
72	2020 Customer Facing Enhancements	232,051	46,410
73	2020 Interface Enhancements	50,185	10,037
74	2020 General Software Enhancements	1,488	298
75	2017 CIS Amortization	9,756,286	512,318
76	Total UES Amortization Expense for Account 303	$ 17,833,591	$ 1,585,103

UNITIL ENERGY SYSTEMS, INC.
TEST YEAR USC AMORTIZATION EXPENSE
12 MONTHS ENDED DECEMBER 31, 2020

Workpaper 7.3
Table of Contents

	(1)	(2)	(3)	(4)
LINE NO.	DESCRIPTION	BEGINNING UNAMORTIZED BALANCE 2020[(1)]	2020 AMORTIZATION EXPENSE	ENDING UNAMORTIZED BALANCE 2020
1	Financial Report Writer Replacement	$ 7,350	$ 7,350	$ -
2	Flexi Upgrade	10,798	5,890	4,908
3	Dataview Upgrade	4,553	2,602	1,951
4	Powertax Repair Module	75,709	30,284	45,425
5	USC Time & Billing Enhancements	32,287	12,108	20,179
6	PC & Furniture 032018	310,955	143,517	167,437
7	Software - Facilities WO&PM Tracking/Reporting	17,052	4,991	12,061
8	PC & Furniture 082018	312,111	120,817	191,294
9	Upgrade C-Series Bottomline Check Printing	5,597	1,492	4,104
10	ADP Vacation Enhancements	2,635	687	1,948
11	General Infrastructure Enhancements	9,113	2,377	6,736
12	2018 Flexi upgrade	16,530	4,048	12,482
13	Flexi Report Writer	6,370	1,560	4,810
14	USC Furn & Equipment - Hamp&CSC	4,263	867	3,396
15	IT Control Testing Automation	320,088	21,339	298,749
16	HR & Payroll Record Scanning	26,917	1,794	25,122
17	USC 2019 Furniture & PC's	310,711	20,714	289,996
18	Total	$ 1,473,037	$ 382,438	$ 1,090,598
19	UES Apportionment		27.50%	
20	Total Billed to Unitil Energy Systems		105,171	

NOTES
(1) Projects Installed in 2020 Reflect Total Project Cost

UNITIL ENERGY SYSTEMS, INC.
RATE YEAR USC AMORTIZATION EXPENSE

Workpaper 7.4
Table of Contents

	(1)	(2)	(3)
LINE NO.	DESCRIPTION	TOTAL PROJECT COST	ANNUAL AMORTIZATION EXPENSE
1	Powertax Repair Module	151,418	30,284
2	USC Time & Billing Enhancements	58,522	12,108
3	PC & Furniture 032018	574,070	143,517
4	Software - Facilities WO&PM Tracking/Reporting	24,953	4,991
5	PC & Furniture 082018	483,268	120,817
6	Upgrade C-Series Bottomline Check Printing	7,462	1,492
7	ADP Vacation Enhancements	3,437	115
8	General Infrastructure Enhancements	11,887	396
9	2018 Flexi upgrade	20,241	4,048
10	Flexi Report Writer	7,800	1,560
11	USC Furn & Equipment - Hamp&CSC	4,335	867
12	IT Control Testing Automation	320,088	64,018
13	HR & Payroll Record Scanning	26,917	5,383
14	USC 2019 Furniture & PC's	310,711	62,142
15	SOX Modernization	75,517	15,103
16	USC Time & Billing Upgrade/Replacement	587,704	117,541
17	2020 Flexi Upgrade	25,531	5,106
18	Total	$ 2,693,861	$ 589,489
19	UES Apportionment		27.50%
20	Total Billed to Unitil Energy Systems		162,109

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY

OF

JOHN F. CLOSSON

And

JOSEPH F. CONNEELY

EXHIBIT JCJC-1

New Hampshire Public Utilities Commission

Docket No. DE 21-030

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is John F. Closson, and my business address is 6 Liberty Lane West, Hampton, New Hampshire 03842.

My name is Joseph F. Conneely, and my business address is the same as Mr. Closson's.

Q. Mr. Closson, what is your position and what are your responsibilities?

A. I am the Vice President of Shared Services and Organizational Effectiveness for Unitil Service Corp. ("Unitil Service"), a subsidiary of Unitil Corporation ("Unitil Corp.") that provides centralized management and administrative services to each of Unitil Corporation's affiliates (the "Unitil Companies"). My primary responsibilities are in the areas of Human Resources and Administration.

Q. Please describe your educational background.

A. I earned a Bachelor of Arts degree from the University of New Hampshire in Durham, NH with a major in English and an MBA from the University of New Hampshire.

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("Commission") or other regulatory agencies?

A. Yes, I have testified in front of the Commission in Docket DE 16-384, Unitil Energy Systems, Inc. ("UES", or the "Company") 2016 rate filing.

Q. Mr. Conneely, what is your position and what are your responsibilities?

A. I am the Manager of Organizational Effectiveness and Total Rewards for Unitil Service. My primary responsibilities are payroll, benefits, and Human Resources.

Q. Please describe your educational background.

A. I earned a Business and Finance degree from Saint Anselm College in Manchester, NH and an MBA from the University of New Hampshire in Durham, NH.

Q. Have you previously testified before the Commission or other regulatory agencies?

A. Yes, I have testified numerous times in front of the Commission over the last twelve years, most recently in the 2018 Cost of Gas Proceeding, Docket DG 18-043.

II. SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of our testimony is twofold: we will provide an overview of the Unitil Companies' compensation practices and policies; and we will sponsor the pro forma adjustments made to the following five items of Operating and Maintenance ("O&M") Expense:

(1) Payroll and Related Taxes;

(2) Medical and Dental Insurance;

(3) Pension, Supplemental Executive Retirement Plan ("SERP") and Post-retirement Benefits Other than Pension ("PBOP");

(4) 401(k) Expense; and

(5) Deferred Comp Expense.

III. COMPENSATION PROGRAM

Q. What is the Unitil Service's compensation policy?

A. Unitil Service's policy is to compensate employees at, or near, the median of the market place for base pay and total cash compensation. The total compensation paid to employees, including base pay and incentive compensation, is an amount necessary to attract and retain highly skilled employees to meet the company's service obligations for the direct benefit of the company's customers. Paying employees market level compensation is consistent with that objective.

Q. Please describe the incentive component of overall employee compensation.

A. Unitil Service maintains three Incentive Compensation plans: (1) all nonunion, non-management employees are eligible to participate in the Unitil Service Incentive Plan; (2) key management employees are eligible to participate in the Unitil Service Management Incentive Plan; and (3) all nonunion employees are eligible for Unitil Service's Restricted Stock Plan, although restricted stock grants are typically awarded to employees in key management positions.

For the purposes of awarding incentive compensation, Unitil Service establishes performance objectives, the relevant weights assigned to each objective, and performance standards. The current performance objectives are: customer satisfaction, gas safety, O&M cost per customer, Earnings Per Share, and electric reliability. The incentive compensation plans are administered on a company-wide basis using the combined performance of all Unitil Corporation affiliates. The incentive compensation paid to employees is a fundamental component of the company's overall compensation package, which in the aggregate is consistent with market levels and necessary to attract and retain the highly skilled employees that enable UES to meet its service obligations for the direct benefit of its customers.

As noted below, Unitil Service does not seek recovery of incentive compensation above or below incentive target levels; rather, incentive compensation is adjusted so that only the target level of performance is included in the revenue requirement.

Q. Has Unitil Service performed a market study to evaluate the competitiveness of its total compensation?

A. Yes, the company did a compensation study on behalf of Unitil Service in 2019. The compensation study was developed by Willis Towers Watson ("Towers Watson"), an internationally recognized consulting firm in the area of employment compensation. The study of Unitil Service salaries and benefits was undertaken for the express purpose of comparing them to external markets. Towers Watson assisted in: (1) reviewing competitiveness of base salaries and salary ranges; (2) reviewing and recommending an appropriate and competitive cash incentive plan; (3) recommending changes to the executive plans; and (4) evaluating and recommending changes to all the non-cash employee benefits plans.

Q. On what sources did Towers Watson rely for its market compensation data?

A. Towers Watson used published surveys from its own database as well as information from the Hay Group, and Mercer. Specific survey sources included: the Towers Watson Energy Services Executive Compensation Database; the Towers Watson Energy Services Middle Management and Professional Compensation Database; the Hay Group Salary Survey; the Towers Watson General Industry Call Center and Customer Service Compensation Survey; the Towers Watson General Industry Human Resources Compensation Survey; the Towers Watson General Industry Information Technology Compensation Survey; the Towers Watson General Industry Logistics and Supply Chain Management Compensation Survey; the Towers Watson General Industry Supervisory & Management Compensation Survey; the Towers Watson Office and Business Support Survey; the Towers Watson General Industry Professional, Technical and Operation Compensation Survey; and the Towers Watson General Industry Sales Compensation Survey. In addition, Towers Watson conducted a search of other utility proxy statements on file with the Securities and Exchange Commission to compare the competitiveness of salaries for certain positions.

Q. Did Towers Watson recommend that Unitil Service adopt a competitive position for its compensation and benefits policy?

A. Yes. Towers Watson recommended that Unitil Service continues the policy of paying at, or near, the median for base pay, total cash compensation, and total compensation when compared to their database of utility companies. They also concluded that median pay levels in New England are roughly equal to median pay levels nationwide.

Q. What was Towers Watson's conclusion about the competitiveness of the Unitil Service's pay structure?

A. Towers Watson concluded that the Unitil Service's pay structure was very close to the market median for most job grades and for most positions. With respect to positions and pay grades that were below the market median, Towers Watson made specific recommendations for changes to these pay levels.

Q. What actions have been taken to implement the recommendations of Towers Watson?

A. Unitil Service began to implement the Towers Watson recommendations in 2015 by adjusting the pay ranges for positions that were below the market median and by adjusting grade levels for specific positions as recommended by Towers Watson. The Target Award levels under the Incentive Plan and the Restricted Stock plan were adjusted closer to the market median.

Q. At what intervals does Unitil Service conduct Compensation Studies?

A. Compensation studies are completed every five years. Towers Watson last completed a compensation study in 2019.

Q. How are wages determined for union employees?

A. Union wage rates are established periodically through the collective bargaining process. This helps set fair and equitable wage rate goals to ensure that our union wages attract and retain qualified union employees. Union wages within the utility industry are increasing on average by 3.0 percent per year, and this equates to our current annual wage increases in the contract. Unitil Service completed negotiations of a five-year contract with the union employees in UES effective June 1, 2018. The contract is set to expire on May 31, 2023.

IV. PAYROLL AND RELATED TAXES

Q. **What adjustment was made to payroll?**

A. The payroll adjustment, as reflected on Schedule RevReq 3-2, pages 1 and 2, adjusts the test year payroll charged to O&M Expense for the following:

(1) Annualization of the pay rate increases that have occurred during calendar year 2020 for the union employees; and

(2) The effect of pay rate increases that occurred on January 1, 2021, that will occur on June 1, 2021, and that are projected to occur on January 1, 2022 and June 1, 2022.

These adjustments have been made to the payroll for both UES and Unitil Service.

Q. Please describe the adjustment to UES's payroll.

A. The payroll adjustment to UES's test year payroll is shown on Schedule RevReq 3-2, page 1. The first step was to normalize the test year payroll to reflect incentive compensation at a target payout level. The next step was to annualize the effect of the 2020 union employee pay increase that occurred during the test year. Added to the annualized O&M payroll were the pay rate increases for 2021 and 2022, which were applied separately, by union and non-union categories, and by year, to arrive at the O&M payroll pro formed for 2020, 2021 and 2022 pay rate increases. The 2020 wage increase of 3.0 percent for union employees was based on the contract, effective June 1, 2020.

The wage increases for non-union employees take effect on January 1 each year. On January 1, 2021, the average annual increase was 3.65 percent. For January 1, 2022, the average annual increase for nonunion employees is projected to be the same, 3.65 percent. The actual increase for 2022 will be updated during the pendency of this proceeding when the actual increase is determined as part of the annual salary budget process which will occur in autumn 2021.

The payroll amount was then reduced by the amount charged to capital in order to arrive at the Test Year O&M Payroll, adjusted for target incentive compensation.

The effect of the UES pro forma payroll adjustments for both union and nonunion employees is an increase in O&M of $154,147. See Schedule RevReq 3-2, page 1, column 4, line 11.

Q. Please describe the adjustment to the Unitil Service payroll.

A. The payroll adjustment to Unitil Service's payroll is shown on Schedule RevReq 3-2, pages 1 and 2. The adjustment to the Unitil Service payroll was prepared in a similar manner as the adjustment to UES's nonunion payroll. First, the Unitil Service test year payroll was identified and adjusted to reflect the incentive compensation at a target payout level. Next, the amount included in the monthly billings for services provided by Unitil Service to the UES division was determined. To this amount, the 2021 actual rate increase of 4.40 percent (including market adjustments and promotions) and the 2022 projected rate increase of 4.40 percent were applied separately for each year to arrive at the pro formed payroll for the 2021 and 2022 pay increases. The actual increase for 2022 will be updated during the pendency of this proceeding when the actual increase is determined as part of the annual salary budget process which will occur in autumn 2021. This amount was then reduced by the amount charged to capital in order to arrive at the pro formed O&M payroll amount of the Unitil Service charge. The effect of the Unitil Service pro forma payroll adjustment charged to UES is an increase in O&M of $555,368. See Schedule RevReq 3-2, page 1, column 5, line 11.

Q. **Please describe the adjustment for incentive compensation.**

A. The adjustment for incentive compensation is shown on Schedule RevReq 3-2, page 1, column 6, line 12. The test year incentive compensation was booked to the target level so no adjustment is required.

Q. What is the total adjustment to the test year payroll for the pay rate increases described above and for the normalization of the Incentive Compensation expense?

A. The total adjustment to the test year payroll is $709,516 as reflected on Schedule RevReq 3-2, page 1, column 6, line 13.

Q. Have you prepared a payroll tax adjustment?

A. Yes, as shown on Schedule RevReq 3-20, an adjustment was prepared to pro form the amount of the Social Security and Medicare taxes related to the payroll adjustments described above.

Q. Please describe how the payroll tax adjustment was calculated.

A. The payroll tax adjustment is shown on Schedule RevReq-3-20. The total O&M payroll increase of $706,516 as shown on Schedule RevReq-3-2, page 1, column 6, line 13 was multiplied by the Social Security rate of 6.2 percent, deriving the additional Social Security tax amount of $43,990. To determine the additional Medicare tax, the total O&M payroll increase of $709,516 was multiplied by the Medicare tax rate of 1.45 percent, deriving the additional Medicare tax amount of $10,288. The total of additional Social Security and Medicare taxes is $54,278.

Q. Have test year payroll taxes been adjusted for Employee Retention Credits ("ERC") and Families First Coronavirus Response Act ("FFCRA") credits?

A. Yes, as shown on Schedule RevReq-3-20. Page 2, an adjustment of $106,244 was prepared to remove the reduction to test year payroll taxes as a result of the

Company's use of ERC, which were enacted as part of the Coronavirus Aid, Relief, and Economic Security ("CARES") Act to incentivize companies to retain employees, as well as FFCRA credits. The adjustment is supported and presented in the Testimony of Mr. Jonathan Giegerich.

V. MEDICAL AND DENTAL INSURANCE

Q. Please describe Unitil Service's current medical and dental insurance plan.

A. Unitil Service provides a Consumer Directed Health Plan ("CDHP") to its employees. The CDHP has two parts: a high deductible health insurance plan and a health savings account ("HSA") funded with pre-tax dollars for out-of-pocket medical expenses. The deductible is $1,500 for individual coverage and $3,000 for two-person coverage, and family coverage. Unitil Service contributes one-third of the deductible to the employees' HSAs. After the deductible is satisfied, coinsurance of 10 percent applies, up to an annual out-of-pocket maximum of $3,000 for individual coverage and $6,000 for two-person and family coverage. Coinsurance for out-of-network coverage is 30 percent with higher out-of-pocket maximums.

Unitil Service also offers two dental plans, a standard plan for union employees with a maximum annual benefit of $1,500; and a premium plan for nonunion employees with a maximum annual benefit of $2,000. Both plans provide preventive care, restorative care and orthodontic benefits.

Q. What steps has Unitil Service taken to contain the increases in the medical insurance expense?

A. Unitil Service has taken several steps to contain these costs:

- Unitil Service periodically compares the coverage and cost of its insurance programs to market alternatives. This review is conducted for UES individually and as part of the Unitil Companies, to ensure that the value for the cost of insurance is maintained, and that costs are contained as much as feasible.
- On January 1, 2007, Unitil Service introduced a Consumer Directed Health Plan as an option for its nonunion employees. The premiums for the CDHP are significantly lower than the Company's other medical plan offerings.
- Effective January 1, 2010, the CDHP was the single health plan offering for Unitil Service's non-union employees.
- Effective January 1, 2011, a coinsurance feature of 10 percent was added to the CDHP. Coinsurance is the percentage of allowed charges for which the member is responsible after the deduction is satisfied. In addition, Unitil Service increased the stop-loss limit on claims from $125,000 to $200,000.
- Prior to January 1, 2018, Unitil Service offered an Exclusive Provider Organization Plan ("EPO") plan to union employees hired before April 1, 2012. This plan was discontinued through the collective bargaining process and the CDHP became the single health plan offering for all union

employees. Costs for EPO plan were significantly higher than the CDHP plan.

Q. As stated earlier, with the assistance of Towers Watson, Unitil Sercice performed a benefits study in 2019. On what sources did Towers Watson rely for its market data?

A. Towers Watson based its study on the benefits data provided to it by 14 peer utility companies who participate in Towers Watson's benefits surveys. Included in the list of peer utility companies are five New England companies.

Q. What was Towers Watson's conclusion about the competitiveness of the Unitil Service's benefits?

A. Towers Watson concluded that, on a total value basis, Unitil's overall benefit program is aligned with the market median.

Q. What is the purpose of the Medical and Dental Insurance Adjustment?

A. The medical and dental insurance adjustment, as developed on Schedule RevReq 3-4, was prepared to pro form for changes in insurance rates that will occur during 2021 and are forecasted to occur on January 1, 2022. We have made these adjustments to the medical insurances for both UES and Unitil Service.

Q. Please describe how the Medical and Dental Insurance adjustment was calculated.

A. The adjustment for Medical and Dental Insurance is shown on Rev Req 3-4. An employee participant count was developed for each plan by type of coverage (i.e., individual, two-person or family). This employee participant count excluded employees who choose to opt-out of the medical and/or dental plan. The 2021 rates were applied to the employee participant counts to derive the annual costs related to the plans. The Medical and Dental insurance costs were then reduced 20 percent, the amount that all employees contribute toward the cost of their coverage. Added to these costs were amounts to reflect payments to employees who choose to opt out of the medical plan and the Unitil Service's contributions to the employees' HSAs. These costs were increased by 9.0 percent for medical and 4.0 percent for dental to reflect the effect of the projected 2022 rate increases, which will be updated during the pendency of this proceeding when the actual 2022 rates are determined. The Medical and Dental costs were then reduced by the amounts chargeable to capital to determine the pro formed Medical and Dental Insurance O&M expense of $219,155. This amount was compared to the Medical and Dental Insurance costs developed for 2021 based on the 2021 rates to derive the 2021 and 2022 increase of $123,234 as reflected on Schedule RevReq 3-4, column 3, line 3.

Q. Please explain the adjustment for the Medical and Dental Insurances that are allocated to UES through the Unitil Service charge.

A. This adjustment is shown on Schedule RevReq 3-4. Similar to UES, the nonunion employees of Unitil Service are all covered under the CDHP. Union employees of Unitil Service hired prior to January 1, 2017 have a choice of coverage under the CDHP or the Preferred Provider Organization ("PPO") Plan. For union employees hired after January 1, 2017, the CDHP is the only plan offered.

The PPO plan provides both in and out-of-network services. No deductible or coinsurance is required for in-network services, but a copayment is required for most services. Out-of-network services are subject to a $400 per person annual deductible ($800 per family) followed by 50.0 percent coverage for the remaining covered medical expenses.

The Unitil Service Medical and Dental costs are allocated among the client companies of Unitil Service on the basis of labor charged. The pro formed adjustment was calculated in an identical manner as the UES adjustment, except for this allocation process. To proform the effect of the 2021 and 2022 rates, a Unitil Service employee participant count was developed. The employee participant count excluded employees who choose to opt out of the medical plan. The 2021 rates were applied to this employee particpant count to derive the 2021 annual costs. Subtracted from these costs were amounts that Unitil Service employees contribute toward the cost of their coverage. Added to these costs were amounts to reflect payments to employees who choose to opt out of the medical plan, and Unitil Service's contributions to the employees' HSAs. These costs were then increased by 9.0 percent for medical and 4.0 percent for dental to reflect the effect of the projected 2022 rate increases, which will be updated during the pendency of this proceeding when the actual 2022 rates are determined. The Unitil Service allocation factor for UES was applied to this amount and the allocated amount was reduced by the amount chargeable to capital. The resulting O&M expense was then compared to the Medical and Dental Insurance cost developed for 2021 based on the 2021 rates to derive the 2021 and 2022 increase of $359,921. This amount is shown on Schedule RevReq 3-4, column 4, line 3.

VI. PENSION, SERP AND PBOP PLANS

Q. Please describe the current Pension, SERP and PBOP plans sponsored by the Unitil Service.

A. Unitil Service sponsor the Unitil Corporation Retirement Plan ("Pension Plan") which provides monthly retirement income to employees who qualify for a retirement benefit. The Pension Plan retirement benefits are based upon an employee's level of compensation and length of service. At the end of the test year, the Pension Plan covered approximately 700 people, including 225 people who are currently receiving benefits. The Pension Plan maintains an investment trust fund for the management of the Plan's assets and the funding of current and future retiree pension benefits.

Unitil Service also maintains a Supplemental Executive Retirement Plan ("SERP"), a non-qualified defined benefit plan which is self-funded. The SERP is designed to encourage service by the participating executives until retirement and to then provide a retirement benefit which, when added to other retirement income of the executive, will ensure a competitive level of retirement income when compared to other utilities. The SERP is a component of executive compensation that was evaluated in the Towers Watson 2019 compensation study and determined to be competitive with the peer group. Eligibility for participation in the Plan was limited to executives selected by the Board of Directors; the SERP was closed to new participants in 2018. Currently, the SERP provides benefits to four retired executives while two active employees are currently eligible.

The Unitil Service also sponsors a Post-Retirement Benefits Other than Pension ("PBOP") Plan, which provides a variety of health and welfare benefits to approximately 270 employees and 327 retirees and their beneficiaries through the end of the test year. For postretirement benefits, the PBOP Plan provides health insurance benefits for retirees and their spouses under age 65; a Medicare Supplement insurance plan for retirees and spouses over age 65; partial reimbursement of Medicare premiums, and a modest paid-up life insurance benefit for retirees. Eligible widows and widowers of deceased retirees are also covered by the health insurance benefits. The PBOP Plan currently maintains two Voluntary Employee Trusts and a 401(h) Account within the Pension Plan to fund covered benefits.

With a few exceptions, the Pension and PBOP Plans of Unitil Service cover union and non-union employees equally and the provisions of the plans and the benefits provided under the plans apply to management and non-management in the same way.

Q. How long has the Pension Plan been in place?

A. The current Pension Plan is a consolidated retirement plan that resulted from the merger of various predecessor plans, some of which dated back to 1959. The current plan was amended in 2009 following the acquisition of Northern and Granite State Gas Transmission, Inc. by Unitil Corporation. The Pension Plan currently offers a defined pension benefit to all eligible employees of the Unitil Service, including the employees of UES. Certain predecessor plan benefits are grandfathered in accordance with IRS regulations.

Effective January 1, 2010, the Retirement Plan was closed to nonunion new hires and it was closed to UES union employees hired subsequent to April 1, 2012. These changes were made as a result of various changes in accounting rules and funding rules which made maintaining a defined benefit pension plan more expensive.

Although these new hires are not eligible for any benefits from the defined benefit pension plan, they are eligible for the 401(k) plan which has been enhanced for this group of employees in order to replace the benefits that have been provided by the defined benefit plan. Further, the 401(k) plan provides this group of employees with ownership, control and portability of their retirement benefits, which are not features that are possible with the traditional defined benefit pension plan.

Q. How long has the SERP been in place?

A. The SERP was originally established and adopted effective January 1, 1987, and was amended and restated effective January 1, 1998, and again effective December 31, 2007. The SERP was further amended and restated in its entirety, effective December 31, 2016, primarily to amend the definition for Final Average Pay and to add an Article setting forth the procedure for any claims and appeals in the event of non payment of benefits. As noted earlier, in 2018 the SERP was closed to new entrants.

Q. How long has the PBOP Plan been in place?

A. Unitil Service has provided post-retirement health and welfare benefits dating back to 1970 and earlier. While these benefits were once fairly common within the utility industry, most companies now require retiree contributions toward the cost of these plans. In an ongoing effort to manage the cost of these plans, effective January 1, 2010, the following changes were made to the PBOP for all nonunion employees and for union employees of UES. Employees in these groups who retire subsequent to January 1, 2010 will now contribute 20 percent of the cost of their retiree medical benefits. The new contribution level includes both the medical benefits before age 65 and the Medicare supplement benefits after age 65. In addition, future retirees will not receive the partial reimbursement toward their Medicare premiums. Further, employees hired subsequent to January 1, 2010 will only be provided with Unitil Service subsidized medical insurance until they reach age 65, but will not be eligible to receive a Medicare supplement plan after age 65.

Q. Who oversees the investment of the Pension and PBOP trust funds?

A. Oversight and monitoring of the investments of the trust funds are ultimately the responsibility of the Unitil Corporation Retirement Plan Committee (the "Committee"), which is appointed annually by the Unitil Corporation Board of Directors, in conformance with the Employee Retirement Income Security Act ("ERISA"). This Committee currently consists of five members: four outside Board members, and Unitil Corporation's Chief Financial Officer. The Committee relies on the advice of investment managers to determine appropriate and prudent investment strategies in compliance with the regulatory and prudence guidelines of ERISA. The Committee also relies on the advice of its actuaries, attorneys, accountants and other consultants to develop the key assumptions used by Unitil Corporation's actuaries to value the Plan's assets and liabilities and determine the annual pension expense, cash funding and other accounting information as required by the rules and regulations of the Security and Exchange Commission, Department of Labor, Internal Revenue Service and other governing regulatory agencies.

Q. Are you sponsoring any adjustments to the Pension, SERP and PBOP expenses?

A. Yes, we are.

Q. Please describe the adjustment made to the Pension, SERP and PBOP expenses.

A. These adjustments are detailed on Schedule RevReq 3-5. Each year, an actuary determines the annual Pension, SERP and PBOP expenses based on a variety of factors including a participant census, discount rates, expected return on plan assets, rate of compensation increase and medical trend rates. A comparison of the 2021 O&M expense to the 2020 test year O&M expense for the Company and for Unitil Service (allocable to the Company) reflects a total increase in pension expense of $62,288, a total increase in SERP expense of $85,989 and a total decrease in PBOP expense of $41,636.

VII. 401(K) PLAN

Q. Please describe the Unitil Service Tax Deferred Savings and Investment Plan (401(k) Plan) sponsored by the Unitil Companies.

A. The 401(k) Plan was established for the benefit of Unitil Service employees, effective January 1, 1985. For eligible employees who are participants in the Pension Plan, Unitil Service matches employees' 401(k) contributions up to 3.0 percent of base pay. Employees who are not participants in the Pension Plan are eligible for the enhanced features of the Plan where Unitil Service both matches employees' 401(k) contributions up to 6.0 percent of base pay and makes a 401(k) contribution equal to 4.0 percent of an employee's base pay.

Q. What is the purpose of the Company's 401(k) adjustment?

A. The purpose of the adjustment is to update Unitil Service's 401(k) costs to reflect the effect of the wage increases that took effect in 2021 and that are projected to take effect in 2022. As shown on Schedule RevReq 3-5, the total 401(k) costs adjustment increases test year expense by $41,844 (column 2, line 16).

Q. Please describe how the 401(k) adjustment was calculated for UES.

A. The 401(k) pro forma costs were determined by multiplying the test year 401(k) expense by the 2021 average pay rate increase. To that amount a projected 2022 pay rate increase was added. The resulting pro forma costs for 401(k) were then reduced by the amount chargeable to construction to determine the pro forma O&M expense of $102,860. The test year O&M 401(k) cost was then deducted to derive the O&M 401(k) increase of $6,187.

Q. Please describe the adjustment to the Unitil Service 401(k).

A. The Unitil Service cost adjustment for 401(k) is determined in a similar manner as the adjustment to UES as shown on Schedule RevReq 3-5. First the test year 401(k) costs apportioned to UES are determined. Those costs are then increased by the 2021 average pay rate increase. To that amount, a projected 2022 pay rate increase was added. The pro forma costs were reduced by the amount chargeable to capital to derive the pro formed O&M 401(k) expense of $432,136. The test year O&M 401(k) was then deducted to derive the O&M 401(k) increase of $35,658 (column 4, line 16).

VIII. DEFERRED COMPENSATION PLAN

Q. Please describe Unitil Service's Deferred Compensation Plan.

A. In 2019 Unitil Service enrolled in a nonqualified deferred compensation plan. Enrollment in this plan allows Unitil Service to provide competitive compensation packages required to attract and retain key employees following the restriction of any new enrollment in Unitil Service's Pension Plan or the SERP.

Q. Please describe Unitil Service's Deferred Compensation Plan Adjustment.

A. The deferred compensation plan pro formed adjustment was determined by multiplying the 2021 deferred compensation expenses $280,214, plus the 2021 deferred incentive compensation expenses $95,220, plus the deferred compensation adjustment for 2022 wage increase $3,473 by the percentage allocated to the Company (28.17 percent). This value is then reduced by the amount chargeable to capital to derive the pro formed deferred compensation pro formed adjustment of $77,097. The test year O&M deferred compensation was then deducted to derive the O&M deferred compensation increase of $64,957. Please see Schedule RevReq Workpaper 4.6.

IX. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY

OF

JOHN F. CLOSSON

EXHIBIT JFC-1

New Hampshire Public Utilities Commission

Docket No. DE 21-030

TABLE OF CONTENTS

<u>EXHIBITS</u>

Exhibit JFC-2	Proposed Seacoast Region Facility Project Decision Document
Exhibit JFC-3	Buildings and Land Search Locations Matrix
Exhibit JFC-4	Outage Response Time Comparison
Exhibit JFC-5	Capital Budget Authorization for New Seacoast Regional Facility Construction
Exhibit JFC-6	Capital Budget Authorization for Acquisition of Land for New Seacoast Regional Facility and Sale of Existing Seacoast Distribution Operations Center

I. INTRODUCTION

Q. Please state your name and business address.

A. My name as John F. Closson. My business address is 6 Liberty Lane West, Hampton, New Hampshire 03842.

Q. What is your position and what are your responsibilities??

A. I am the Vice President of People, Shared Services, and Organizational Effectiveness for Unitil Service Corp.("Unitil Service"), which provides centralized utility management and administrative services to Unitil Corporation's ("Unitil Corp") utility operating subsidiaries, including Unitil Energy Systems, Inc. ("UES" or the "Company"). Unitil Service and Unitil Corp's utility operating companies are referred to collectively as the "Unitil Companies." My responsibilities include leading the human resources, procurement, inventory management, fleet management, facilities management, business resiliency, environmental health and safety, and administrative services functions for the Unitil Companies.

Q. Please describe your business and educational background.

A. I have over 15 years of professional experience in the utility industry supporting electric and natural gas operational business units. I joined Unitil Service in 2008 in the role of Manager, Procurement and Supply Chain. In 2016 I was promoted to the role of Director of Shared Services. In 2019 I was promoted to my current position of Vice President of People, Shared Services and Organizational Effectiveness. Prior to joining Unitil Service, I was employed for four years at National Grid, USA where I held various positions supporting National Grid's Supply Chain Management teams. I hold a Bachelor of Arts and Master of Business Administration from the University of New Hampshire.

Q. Have you previously testified before the New Hampshire Public Utilities Commission (the "Commission") or other regulatory agencies on behalf of the Unitil Companies?

A. Yes, I testified before the Commission in 2016 for the Docket DE 16-384.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of this testimony is to describe the Company's Seacoast Regional Facility Project. This three year project centered on the construction of a 53,940 square feet ("sf") multiuse facility located at 30 Energy Way, Exeter, New Hampshire. The project addressed a number of longstanding facility and space issues facing the Company and Unitil Service. The project was completed in late fall 2020. In December 2020, approximately seventy employees relocated to the new Seacoast Regional Facility. This new facility provides improved operational performance for the Company's Seacoast Electric Operations division while addressing critical redundancies needed throughout the organization.

III. SEACOAST REGIONAL FACILITY

Q. What is the Seacoast Regional Facility?

A. The new Seacoast Regional Facility is a multiuse facility that acts as the base of operations for the Company's Seacoast Electric Operations division. The facility also houses a number other services that support all of Unitil Corp's subsidiary companies. These services include Central Electric Dispatch, Electric Engineering, Forestry Operations and Sustainability. The Seacoast Regional Facility also provides essential redundancies for Unitil Service's electric, gas, and emergency operations functions. The new Seacoast Regional Facility consists of offices, conference rooms, warehouse, labs, workshops, garage, and material storage yard.

Q. Can you describe these essential redundancies?

A. Yes, the Seacoast Regional Facility provides essential redundancies for three of Unitil Service's critical functions. The critical functions are Gas Control, System Level Emergency Operations Center, and Operator Qualification ("OQ") Testing and Training. Each of these critical functions serves multiple Unitil Corp subsidiary operating companies. Gas Control monitors gas distribution systems in three states on a 24/7 basis from Unitil Service's office in Portsmouth, New Hampshire. The Seacoast Regional Facility was designed with a dedicated space for Gas Control to run its operations should the Portsmouth facility become compromised in any way. Unitil Service's System Level Emergency Operations

Center is based at its corporate headquarters in Hampton, New Hampshire. In the event the Hampton facility becomes unavailable the System Level Emergency Operations Center can be operated out of the new Seacoast Regional Facility. Finally, Unitil Corp's subsidiary natural gas operating companies (Fitchburg Gas and Electric Light Company, Northern Utilities, Inc. and Granite State Gas Transmission, Inc.) have adopted the Northeast Gas Association's ("NGA") Operator Qualification program. One requirement of the NGA program dictates all individual qualification testing be completed in a space managed by global testing services provider, Prometric. Prior to the construction of the new Seacoast Regional Facility the only internal location for Unitil Service employees to be tested in accordance with the Prometric standards was at Northern Utilities, Inc.'s Portland, Maine facility. The Seacoast Regional Facility was constructed with a Prometric compliant testing and training center. The addition of the Prometric compliant testing and training center at the new Seacoast Regional Facility provides both redundancy and proximity benefits for Unitil Corp's subsidiaries' natural gas workers in New Hampshire and Massachusetts.

Q. What teams are assigned to the Seacoast Regional Facility as their primary reporting location?

A. All of the Company's Seacoast Electric Operations teams, including Metering, Overhead Line Department, and Field Services, are assigned to the Seacoast Regional Facility. Also, there are a number of Unitil Service employees reporting to the Seacoast Regional Facility. These employees are from the following departments: Central Electric Dispatch, Electric Engineering, Forestry Operations, Sustainability, and Electric Substations.

IV. EXISTING CONDITIONS

Q. Where did the Company locate its electric operations teams prior to the construction of the Seacoast Regional Facility in Exeter?

A. The Company's Seacoast Electric Operations division was located at 114 Drinkwater Road in Kensington, New Hampshire.

Q. Was the facility at Drinkwater Road adequate for the needs of the Company's Seacoast Electric Operations division?

A. No, the Drinkwater Road facility had a number of limitations that impacted the Company's ability to safely provide reliable service to its customers as well as a positive working environment for its employees. The Drinkwater Road facility was constructed in 1954, and many aspects of the facility remained unchanged from that time. In the 1960's there was a renovation at the facility which expanded its total square footage to just over 21,000sf.

The age and size of the Drinkwater Road facility rendered it inadequate for the Company's Seacoast Electric Operations division. For example, the garage at the Drinkwater Road facility was designed for individual bays for each vehicle. The openings constructed for each overhead door in the garage at the Drinkwater Road facility is not adequate for modern features such as additional insulation, casing and hydraulics found on contemporary utility bucket trucks. Without renovation, future utility bucket trucks may no longer be able to enter the garage at the Drinkwater Road facility causing logistic complications. Additionally, the low ceiling in the garage also resulted in poor ventilation. The Company installed an auxiliary ventilation system in an attempt to address the issue and improve air quality, but the improvement did not fully address the Company's needs.

The Drinkwater Road facility's electrical, heating, plumbing, and emergency power (generator) systems are in need of costly repair or replacement. Furthermore, the facility did not have a fire suppression system, putting many Company assets at risk.

Heating and cooling expenses at the Drinkwater Road facility were high, due to a lack of insulation coupled with single pane windows found throughout the facility. Renovation or replacement of the windows, or other elements of Drinkwater Road facility, are hampered by the presence of asbestos in the window caulking, pipe insulation and flooring of the facility.

The material storage yard at the Drinkwater Road facility did not meet the needs of the Company's Seacoast Electric Operations division. The layout of the material storage yard did not allow for the easy access and egress of Company vehicles. Additionally, Drinkwater Road's material storage yard was suited for a time when utility poles and equipment were much smaller than they are today.

Expansion of the material storage yard at Drinkwater Road would require impacting wetlands located just behind the facility.

Drinkwater Road itself has presented challenges to the Company's Seacoast Electric Operations as it has flooded a number of times forcing access to the facility to be limited to one direction. See Exhibit JFC- 2 for a thorough description of the existing conditions at the Drinkwater Road facility.

Q. **Were there additional facility or space issues in other parts of the organization beyond the needs of the Seacoast Electric Operations divisions?**

A. Yes, Unitil Service faced facility and space challenges at both its corporate headquarters in Hampton, New Hampshire and its Portsmouth, New Hampshire facility. At Unitil Corp's Hampton office, occupancy was at its limit based on the configuration of systems furniture (cubicles) in that office. Employees were going to have to relocate out of that office, or a renovation would be required, to accommodate additional staffing.

After thorough analysis, it was decided that the Forestry Operations, Sustainability, and Electric Engineering departments would relocate from the corporate headquarters in Hampton to the new Seacoast Regional Facility. These teams presented the best operating synergies with the Company's Seacoast Electric Operations division. The relocation of these teams relieved the occupancy constraints at the corporate headquarters in Hampton.

Unitil Service's Central Electric Dispatch team was located at Unitil Service's Portsmouth, New Hampshire office. The accommodations for the Central Electric Dispatch team were inadequate in the Portsmouth office. Often, Electric Dispatchers would need to leave the operation unattended as they visited breakrooms or used the restroom. The management team for Unitil Service's Electric Substation Operations also reported out of the Portsmouth office; primarily to be adjacent to the Central Electric Dispatch team. Both the Central Electric Dispatch team and the Electric Substation Operations relocated from Unitil Service's Portsmouth office to the new Seacoast Regional Facility.

Q. How did the new Seacoast Regional facility address the challenges you described?

A. The new Seacoast Regional Facility in Exeter allowed the Company's Seacoast Electric Operations division to relocate to a facility adequate for its needs. The new Seacoast Regional Facility provides ample material and vehicle storage along with the addition of workshops and testing labs required to evaluate and manage the evolving technologies in the utility sector. At the new Seacoast Regional Facility, Unitil Service's Central Electric Dispatch team has a best-in-class operations center to perform their duties. The Central Electric Dispatch operations center incorporated a restroom and small kitchen into its design to eliminate the need for staff to leave the space during their shifts. Also, the space issues in Unitil's corporate headquarters and Portsmouth office were alleviated by the new Seacoast Regional Facility. Finally, the close proximity of departments which commonly interact (e.g. Electric Engineering, Electric Substation, Company Seacoast Electric Operations, and Forestry Operations) provides operational efficiencies for normal work and during system emergencies.

V. PRECONSTRUCTION PLANNING AND DESIGN

Q. When faced with a number of facility and space issues did the Company review other locations it owned as possible solutions?

A. Yes, the Company and Unitil Service reviewed all New Hampshire Seacoast region real estate portfolios and no options were identified that would satisfy the requirements for the new Seacoast Regional Facility.

Q. How did the Company determine the extent of its requirements for solving its facility and space issues?

A. The Company undertook an extensive space planning program to determine the requirements for addressing its facility and space challenges. The final requirements were established by an internal team of stakeholders from the Company and Unitil Service with input from key business partners. This team was focused on determining long term solutions to continue the Company's excellence in service while innovating to meet future needs of an evolving industry.

Q. What approaches did the Company consider when trying to address its facility and space issues?

A. The Company thoroughly evaluated four options to address its facility and space issues. These options included: Option 1- renovate the 21,000sf Drinkwater Road facility and build a 10,500sf addition at the corporate headquarters in Hampton; Option 2 - renovate the 21,000sf Drinkwater Road facility including a 10,500sf addition to that facility; Option 3 - demolish the Drinkwater Road facility and rebuild it to address all facility and space needs; and Option 4 - purchase land and build a new facility to address the Company's and Unitil Service's needs. (Please see "Proposed Seacoast Region Facility Project – Decision Document," attached here as Exhibit JFC-2.)

Q. Did the Company consider buying an existing facility and renovating it to suit its needs?

A. Yes, the Company engaged a commercial real estate broker with over 30 years of commercial real estate experience in the New Hampshire's Seacoast market. The Company's real estate broker presented several options in the greater Seacoast area.

Q. What properties did your Real Estate broker identify and why did the Company Unitil Service not proceed with these options?

A. Exhibit JFC- 3 shows a matrix of properties and buildings vetted by the Company's real estate broker. Although several options were presented, many were not viable due to the location of the real estate within the Company's Seacoast electric service territory.

Q. What locations were considered preferential by the Company, and why?

A. Locations along the NH Route 101 corridor between Exeter and Hampton were considered ideal. The bulk of the Company's electric seacoast customer interruptions were in Exeter, Kingston, Stratham, Plaistow and Hampton. Please see Exhibit JFC-4 for a table of customer interruptions between 1/1/2013 and 12/31/2016.

Q. The Company ultimately proceeded with Option 4 - Purchase land and build a new facility. How did the Company arrive at this decision?

A. A number of factors were considered when determining that Option 4 was the best for the Company and Unitil Service overall. Once the regional commercial real estate market was vetted and determined not to have a suitable alternative for the Company, focus turned to renovation and/or construction. Options 1 – 3 centered on renovating the Drinkwater Road facility in Kensington, New Hampshire. The zoning for the Drinkwater Road facility was approved in the 1950's. The current zoning for this district of Kensington, New Hampshire is Residential – Agricultural. Any significant renovation or construction at the Drinkwater Road facility would require a special exception by the town zoning board, per the Board of Adjustment, section 3.3 of the Kensington's Zoning Ordinance. Section 3.3 of the Kensington's Zoning Ordinance outlines that a permit exception would only be granted if the building was compatible to the nature and quality of the neighborhood and if building use is not offensive to the public because of noise, vibration, or excessive traffic.

These zoning stipulations presented a challenge for the Company when considering Options 1-3. Options 1 and 2 each had a total square foot available of 31,500sf. If the Company had proceeded with Option 1 or Option 2 it would have fallen approximately 22,500sf short of the 54,000sf requirement defined in the Company's space planning program. Furthermore, Options 1-3 would require some form of temporary accommodations for the Company's Seacoast Electric Operations teams during construction. Based on the nature of the materials, equipment and vehicles needed by the Company's Seacoast Electric Operations division, identifying a suitable temporary accommodation would have been difficult. Finally, when evaluating the estimated cost per square foot of each Option available to the Company, Option 4, at $285.47 per square foot, was the lowest Option by 11% (see attachment F in Exhibit JFC-2). After considering all of the factors, the Company determined that Option 4 was the best choice to address the organization's facility and space challenges, while maintaining its continuity of service excellence.

VI. POST CONSTRUCTION AND SUSTAINBILITY

Q. How long did it take to construct the new Seacoast Regional Facility?

A. The project took approximately 14 months to complete. There were no significant setbacks to the project, although the COVID-19 pandemic did result in some minor project delays and additional safety protocols.

Q. What was the impact to customers during the Company's transition from the Drinkwater Road facility to the new Seacoast Regional facility?

A. There was no impact to Customers during the transition. The Company phased the move to the new Seacoast Regional Facility over a period of three weeks to ensure no disruption to service would occur. On December 25, 2020, shortly after the Company moved in, the Company's Seacoast Electric Operation division prepared for its first weather event in the new facility. The Company was able to respond to weather related electric system outages without issue. In subsequent weather events, the new Seacoast Regional Facility's emergency operations center capabilities and Center Electric Dispatch technology have proven to be assets to the Company's emergency response.

Q. What steps did the Company take to control ongoing operating and maintenance expenses at the new Seacoast Regional Facility?

A. The Company integrated a number of Sustainability measures into the new Seacoast Regional Facility which will result in lower operating expenses and lower impact on the environment. These measures include: increased insulation for the metal paneling and office roof to increase the R-value of the facility, advanced LED lighting controls to offset energy consumption, enhanced ventilation system in warehouse and garage to employ natural air conditioning, and a rainwater harvesting system that will be used in the vehicle wash bay to offset the use of Town supplied water (Exeter Town water is taxed between $8.38 - $12.57 per 1000 gallons based on total consumption).

Q. Is the Company responsible for all operating and maintenance expenses at the new Seacoast Regional Facility?

A. No. Because Unitil Service employees are utilizing areas of the new Seacoast Regional Facility, Unitil Service is responsible for a portion of the operating and maintenance expenses. An inter-company lease agreement and sub-lease has been established which allocates costs to Unitil Service based on square footage. This allocation will also include shared common areas of the building including restrooms, conference rooms, and breakrooms/kitchens. Unitil Service will reimburse the Company for operating expenses through the inter-company lease agreement.

Q. What is the disposition of the Drinkwater Road facility and what does the Company have planned for that facility?

A. The Drinkwater Road facility is currently unoccupied and being prepared for sale. A number of parties have come forward and expressed interest in the property. Any profit realized from the sale of the facility will be returned to the Company's ratepayers.

Q. What was the final cost of the Facility?

A. To date the total project costs including facility construction, land acquisition, and preparation of the Drinkwater Road property for sale equal $17,517,969. The Company is awaiting final reconciliation from its General Contractor; however, it is not anticipated any significant additional costs will be incurred.

Q. Have you provided copies of the construction authorizations for the project?

A. Yes. Please see Exhibits JFC-5 and JFC-6.

VII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

[THIS PAGE INTENTIONALLY LEFT BLANK]

June 17, 2019

(updated on 6/18/19 w/decision)

Proposed Seacoast Region Facility Project
Decision Document

♦ ♦ ♦ ♦ ♦

submitted to

John F. Closson

VP, People/Shared Services/Organizational Effectiveness

prepared by

Jacqueline D. Agel
Manager, Fleet & Facilities

♦ ♦ ♦ ♦ ♦

New Seacoast Region Facility Build-to-Suit Project
Decision Document

Table of Contents

New Seacoast Region Facility - Decision Document
June 17, 2019

I. Introduction. Following the early 2017 decision to move forward with the planning for a new seacoast region facility the following work has been done.

- A search committee was formed and included representatives from Facilities, Electric Operations, Sr. Management, and a commercial real estate broker. A kick off meeting was held in February 2017.
- The commercial real estate market in Unitil's Seacoast service territory was vetted. There were very few viable options. A commercial building in the Industrial Drive area of Exeter was located but the owner did not want to sell.
- In June 2018 Unitil Energy Systems, Inc. entered into a purchase & sales (P&S) agreement with Garrison Glen, LLC for land in the Continental Drive industrial park in Exeter, NH.
- Following the P&S, Unitil contracted with PROCON, LLC, a design/build (D/B) construction management firm, and Stibler Associates, an interior design firm, to begin preliminary survey(PS) work. The PS work included developing a space program for Unitil's NH Seacoast Region Electric Distribution Operations Center's (DOC) functions, as well as, for some USC functions including Electric Engineering, Central Electric Dispatch, OQ Testing & Training, and business continuity space for Central Gas Control & Field Services. Section III includes brief descriptions of the current status and business requirements of the functions that are slated to move to the new facility.
- A space program was completed by the designers in close collaboration with the managers of each of the functions, in early 2019. The new Exeter facility space program includes 53,940 square feet. *See attachment H for square foot detail.*
  - ✓ DOC (office, conf rms, shops, IT, common, warehouse, garage, wash bay)– 43,448 sf
  - ✓ USC (office, conf rms, OQ Testing/Training Rm, Common, CED, BC) – 10,492 sf
- Unitil has received all permitting approvals from the State of NH and the Town of Exeter. The appeal period has ended for the State permits. The appeal period for the Town of Exeter is anticipated to end on or about July 10th.
- Approximately $600K in preliminary survey costs have been incurred for the Exeter project on legal/permitting, preconstruction/planning engineers & designers, estimating, etc.

II. Purpose. The purpose of this document is to request final approval to construct a new 53,940 sf Unitil Seacoast region facility in Exeter, NH. Specifically, I am seeking approval to close on the purchase and sales agreement for the land in Exeter and enter into a Design/Build Agreement with PROCON. These next steps are included in Section VII.

III. Current Status/Business Requirements

A. Seacoast Region Electric Operations Distribution Center (DOC) – 43,448 sf. The current DOC, located in Kensington, NH, was constructed in the 1954. A small addition was constructed in the 1960s. Due its age and its size this building no longer meets current day operational needs. The size of and quantity of trucks and materials has increased greatly since the 1950s to support the Seacoast region's growing customer base. The garage is too small for contemporary line trucks and the stockyard is tight. The building's electrical, heating, and plumbing infrastructure is antiquated and many systems are in need of replacement including emergency power systems infrastructure (UPS and Generator). The building does not have a fire suppression system which places the operation and company assets at risk. The windows throughout the building are as old as the building and provide no thermal insulation causing the areas adjacent to the windows to be very cold and uncomfortable in the winter. In addition, conference space is inadequate and space for Emergency Operations Center (EOC) activities is very tight.

B. USC/Central Electric Dispatch (CED) – 1100 sf. The current CED space is undersized and is located in Unitil's NH Gas Distribution DOC in Portsmouth, NH. Constructing a new facility in Unitil's Seacoast region is an opportunity to solve CED's deficiencies. The new CED location will provide the space, furniture, and equipment best suited to perform the CED functions. The space will include a restroom and a breakroom directly adjacent to the CED room in support of CED staff with responsibility to monitor Unitil's Electric System 24x7x365. Currently CED personnel must leave the CED space to use the restroom and break room leaving the CED operation unmanned for a period of time because typically one staff member covers a shift, unless staffed for emergencies. The current Portsmouth CED space would remain intact and will provide Unitil with a business continuity solution for CED.

C. USC/Gas Control and Field Services Business Continuity Space – 271 sf. The Gas Control (GC) function is located in Unitil's NH Gas Distribution DOC in Portsmouth. GC supports Unitil's ME, NH & MA Gas Transmission and Distribution Operations. GC has business continuity (BC) space located in a closet at the corporate office in Hampton. The BC space is tiny and is inadequate for a long duration use. The BC space will be used if the primary GC room in Portsmouth could not be used due to fire or other impact to the Portsmouth facility. Constructing a new facility in Unitil's Seacoast region is an opportunity to solve a Unitil business continuity need for its mission critical Gas Control function in addition to a solution for Field Services' BC space requirements. These two functions work very closely together and will occupy the same BC space in the new facility.

D. USC/OQ Testing & Training Room - 1334 sf. The National Gas Associations (NGA) has defined requirements for Operator Qualification (OQ) testing facilities. A Unitil OQ testing space is needed for Unitil's NH Gas Distribution and Transmission operations employees. Most OQ testing is completed between December and April each year. When the space is not in use for OQ Testing it will be available for use by other Unitil departments for training and/or conference space. In addition, the space could be used for business continuity purposes for employees and/or a backup to the System EOC operations currently located in Hampton, NH.

E. USC/Engineering Department - 3236 sf. Moving the electric engineering team from Hampton to the new facility, where the team will be with Seacoast Electric DOC personnel, will work well because the electrical engineers work closely with electric operations personnel. The gas engineering department has occupied the same facility as Unitil's NH Gas DOC personnel, in Portsmouth, for the past 10 years. This adjacency has proven to be efficient because the gas engineers work closely with gas operations personnel. Moving electric engineering out of the Hampton office, which is at capacity, will provide the space needed for new IT FTEs hired to support of Unitil's IT infrastructure, business systems, projects, and cyber security in addition to other USC space needs.

IV. Options. The following four (4) options were evaluated. The benefits and risks for each option are included following the introduction of the options below. Back up information and more detail in connection with these options can be found in Attachments A & D.

Option #1: Renovate 21,000 sf at existing DOC building and build a 10,500 sf addition at the Hampton office. This option does not include the space required (43,448 sf) to efficiently operate a current day DOC per the space program that has been developed for Business Requirement A above.

Option #2: Renovate existing 21,000 sf DOC and construct a 10,500 sf addition on the existing building. This option also does not include the space required (43,448 sf) to efficiently operate a current day DOC per the space program that has been developed for Business Requirements A above.

Option #3: Remove the existing, 21,000 sf DOC building and construct a new Seacoast region facility in its place. This option includes the total sf (53,940) from the space program that was developed to address Unitil's Business Requirements outlined in A through E above.

Unitil

New Seacoast Region Facility - Decision Document
June 17, 2019

Option #4: Purchase land and construct a new Seacoast region facility. This option includes the total sf (53,940) from the space program that was developed to address Unitil's Business Requirements outlined in A through E above.

Notes:

- Options 1, 2, and 3 were vetted at a high level. Preliminary Survey costs incurred for Option 4 were used for estimating soft costs for options 1, 2 and 3.
- Option 4 has been vetted over the past year.

OPTION #1	Total sf	Cost	Cost/sf
	31,500	$ 12,385,100	$393.18

Scope

Renovate Existing Seacoast DOC - 21K sq ft (See Attachment A - Kensington Study)

Build Addition on Existing Hampton Office - 10.5K sq ft (See Attachment D - Hampton Addition)

Benefits

1	No land or building acquisition costs.

Risks

1	The Town of Kensington's zoning may not support this option. See zoning section on page 1 of Attachment A.
2	The existing 21K sf DOC building footprint would not change and would not include all of the DOC space program (43K sf) defined for current day DOC operational needs.
3	Abatement of asbestos containing materials. Asbestos is present in the existing facility but the extent of the presence of these materials is unknown.
4	No municiple water or sewer is available and the cost for a compliant leach field and the infrastructure needed to support a fire suppression sprinkler system will be costly.
5	Relocation of operations during renovations will be required and the availabilty of commercial lease options within the service territory are scarce (see Attachment B).
6	Costs for a temporary NNN lease (see Attachment E). A NNN lease costs include monthly rent *plus* property taxes, insurance, CAM, utilities.
7	Costs for fit up, furniture, furnishing, for a commercial lease space.
8	Costs and business disruption to relocate to leased space (movers, DOC staff time, IT and Facilities staff time, telecomm, etc.)
9	Disruption to Hampton office during construction of an addition.
10	Soft costs nearly doubled for designers/legal/permitting in connection with pre-construction and construction administration services for the renovation of the Kensington building and an addition to the Hampton building.
11	Cost and availability of additional Unitil resources needed to manage and administer (2) large facilities projects

Unitil

New Seacoast Region Facility - Decision Document
June 17, 2019

OPTION #2	Total sf	Cost	Cost/sf
	31,500	$ 11,869,200	$376.80

Scope

Renovate Existing Seacoast DOC - 21K sq ft (See Attachment A - Kensington Study)
Build Addition on Seacoast DOC - 10.5K sq ft (See Attachment A)

Benefits

1 No land or building acquisition costs.

Risks

1 The Town of Kensington's zoning may not support this option. See zoning section on page 1 of Attachment A.

2 The existing 21K sf DOC building footprint would not change and would not include all of the DOC space program (43K sf) defined for current day DOC operational needs.

3 Abatement of asbestos containing materials. Asbestos is present in the existing facility but the extent of the presence of these materials is unknown.

4 No municiple water or sewer is available and the cost for a compliant leach field and the infrastructure needed to support a fire suppression sprinkler system will be costly.

5 Relocation of operations during renovations will be required and the availabilty of commercial lease options within the service territory are scarce (see Attachment B).

6 Costs for a temporary NNN lease (see Attachment E). A NNN lease costs include monthly rent *plus* property taxes, insurance, CAM, utilities.

7 Costs for fit up, furniture, furnishing, for a commercial lease space.

8 Costs and business disruption to relocate to leased space (movers, DOC staff time, IT and Facilities staff time, telecomm, etc.)

OPTION #3	Total sf	Cost	Cost/sf
	53,940	$ 17,224,200	$319.32

Scope

Construct New Facility on Existing Seacoast DOC parcel in Kensington, NH

Benefits

1 No land or building acquisition costs.

2 Ability to construct all requirements of the DOC space program (43K sf) and additional 10.5K sf for USC space needs.

Risks

1 The Town of Kensington's zoning may not support this option. See zoning section on page 1 of Attachment A.

2 The undeveloped land surrounding the existing DOC is wet and subsurface conditions could make the cost of construction higher than estimated. It may be determined that none of the land is suitable for this use.

3 Cost of demolishing existing DOC

Unitil

New Seacoast Region Facility - Decision Document
June 17, 2019

OPTION #4	Total sf	Cost	Cost/sf
	53,940	$ 15,398,319	$285.47

Scope
Construct New Facility on Land in Exeter, NH

Benefits

1	Land is zoned for commercial use.
2	Municiple water or sewer is available.
3	Construct all requirements of the DOC space program (43K sf) & additional 10K sf space needs.
4	Implement best environmental storage practices for poles and transformers.
5	Sell existing DOC. Estimated value is $800K.
6	State and Town permits have been issued and construction can start in late July/early August.

Risks

1	Unitil does not own the land. P&S cost is $1M
2	Although unsuitable subsurface conditions are not anticipated, due to geotech borings/testing, there is still a chance that they exist and could add unanticipated site work costs.

V. Recommendation. Option #4. This option poses the least amount of risks due to the following: the land is zoned for commercial use, the subsurface conditions are known because geotechnical borings have been studied and therefore unforeseen unsuitable conditions are not anticipated. The estimated cost/sf is the lowest of all of the options, the location is more central within Unitil's NH Seacoast Electric service territory and is less than one (1) mile from Rte 101 which is a main corridor and easily connects to other main corridors in the service territory. See attachment I.

Option #4 Costs
Estimated 2019 Spend: $7,470,578.00 (Land, PS&I, Road, Construction & Construction Admin)
Estimated 2020 Spend: $7,927,741.00 (Construction & Construction Admin, Furniture, etc.)
Total: $15,398,319.00

VI. Decision/Approval: On June 18, 2019 Unitil's CFO and CEO approved proceeding with the recommendation outlined in section V. above.

VII. Next Steps/Schedule. If the recommendation is approved the next steps include;

1. June 21 – GMP (Guaranteed Maximum Price) submitted to Unitil by PROCON
2. June 28 – Conclude GMP negotiations
3. July 1 - Road dedication approval from the Select Board
4. July 2 – Finalize Design/Build Construction Management Contract w/ final GMP
5. July 3 – Initiate Authorization for 2019 construction budget item
6. July 10 – The final permitting appeal period ends following Planning Board approvals
7. July 18/19 – Close on Purchase & Sales Agreement
8. July 22 – Mobilize for ground breaking

Attachment

PROCON
CONNECT • CREATE • CONSTRUCT

T 603.623.8811
F 603.623.7250
P.O. Box 4430
Manchester, NH 03108

To: Jacquie Agel – Unitil/Manager, Fleet & Facilities
Cc: Mark E. Beliveau – Partner/Pierce Atwood LLP
From: Mike Lawrence – Sr. Architect Project Manager
Date: March 26, 2019
RE: Unitil Energy Systems, Inc. – Kensington Study

INTENT OF THE STUDY
The intent of this analysis is to understand if any of three options are permissible and/or could be permitted given the constraints of the site and the condition of the current facility, as well as, what the advantages and disadvantages of each option are and to identify the potential costs for each option.

Option 1: Fully renovate the existing building including the building systems, exterior building envelope and interior fit-up. The layout of the site would remain the same with some site improvements such as pole storage, a new leach field, and new well.

Option 2: Fully renovate the existing building including the building systems, exterior building envelope and interior fit-up and add a 10,000 square foot addition to the facility. The addition would include space for Engineering, OQ Testing/Training Rm, CED, and Back up Gas Control & Field Services. The site would be expanded to accommodate the new addition, new storage areas, canopies, and building utility services.

Option 3: Remove in its entirety the existing facility and build a 55,000 square foot facility per Unitil's programming requirements. This would include a full redesign of the existing site.

ZONING
Address: 114 Drinkwater Rd, Kensington, NH 03833
Lot: 1,159,048 sf or 26.6 acres
District: Located in the Residential – Agricultural (RA) Zoning District
Based on September 2017 Alta Survey: A portion of the parcel is in a special flood hazard area, zone A.

Setbacks:	**(single family residence)**	**(prohibited use)**
	Front: 25 feet	As a business 100 feet
	Side: 25 feet	As a business 50 feet
	Rear: 25 feet	As a business 50 feet

Summary: Unitil's current use of the site is a prohibited use within this district, and any significant upgrade or addition to this building would require a special exception by the town zoning board, per the Board of Adjustment, section 3.3 of the Town's Zoning Ordinance. If an approval is granted the application would then be referred to the Planning Board for site plan review and a permit would be issue by the Planning Board if acceptable. *From Section 3.3: …no use will be permitted if: 2. the use is not compatible to the nature and quality of the neighborhood; or 3. the use if offensive to the public because of noise, vibration, excessive traffic, unsanitary conditions, noxious odors, smoke, nature of the activity or other similar reasons.*

Unitil Energy Systems, Inc., formally known as Exeter & Hampton Electric Company (E&H), acquired the property by way of three deeds; one in 1954 and two in 1968. The original portion of current building was built in 1955 and in 1962 a 900 sf addition was constructed. . Kensington adopted zoning in 1959 but we don't know how this property was zoned/regulated when E&H developed it. For purposes of this zoning analysis, the assumption made by Unitil's attorney, Mark Beliveau, is that the development of the property was consistent with applicable zoning and, therefore, the use of the building and property today is a lawful non-conforming use.

Under the Kensington ordinance, a lawful non-conforming use or building may not be expanded "for a purpose or in a manner which is substantially different from the use to which it was put before the alteration…." Which means, that the use or building may be expanded as long as such expansion is not "substantially different" from the use to which it was put before the alteration. Substantially different is not defined and is subject to interpretation.

For the Town to grant a special exception, Unitil would need to convince the town that the use (1) would not cause any adverse impacts to health, safety, morals, welfare of the residents of the town or neighborhood property values, (2) is compatible with the nature and quality of the neighborhood, and (3) is not offensive to the public because of noise, vibration, excessive traffic, etc.

EXISTING CONDITIONS

Site

The current facility at 114 Drinkwater Road in Kensington is located within a residential neighborhood, with single family residences on both sides and across the street. The site is relatively flat and surrounded by wetlands. To the north of the existing building there is an open body of water. The building is served by a well to the north of the existing vehicle storage garage and a leach field located to the west of the building. Both the well and leach field are located out of wetland areas, but not wetland boundaries.

If a renovation, addition, or a new facility were to be built at the Kensington site several key site issues would need to be addressed including;

- To provide a sprinkler system to the building a large underground storage tank or a pond would be required due to the building' water being supplied by a well. Without adequate groundwater information our recommendation would be to develop a pond onsite for this requirement.

- A new leach field would be required and could prove difficult with the extent of wetlands on the site. We do not know what the seasonal groundwater level is, but with wetlands surrounding the site it is assumed to be relatively high. This would make installing a leach field with today's regulations difficult and more expensive.
- Current storm water regulations are more restrictive than when the building was originally built and will require more treatment and storage onsite. This may be difficult to achieve with a potentially high seasonal groundwater level and the amount of wetlands onsite.
- Depending on the extent of a renovation, addition or new construction the impact to the surrounding wetlands could be considerable. While the State permitting process is straight forward we do not know how the local conservation committee will react to developing on the wetlands. If the local conservation committee would like to limit development in these areas it would complicate any approvals process. The cost of wetlands mitigation and professional design services should be considered when developing an overall project budget.
- The current circulation through the existing site is not ideal and a renovation or addition would not improve this substantially unless the whole site is redesigned. We would anticipate limiting the site development in the first two options to reduce wetlands impact and improve the potential that the project could get town approvals.
- The existing site does not have transformer and pole storage containment areas, a best environmental practice today. Due to the current size and elongated shape of the yard providing containment for the transformers would be difficult and costly and involve several additional large catch basins and water quality units.
- Geotechnical investigations would be required to determine the soil structure. Due to having extensive wetlands on the site we would anticipate that the soils are not ideal to build upon and potentially require some type of soil improvements.

Photos of the existing yard; including pole and transformer storage areas:

Building

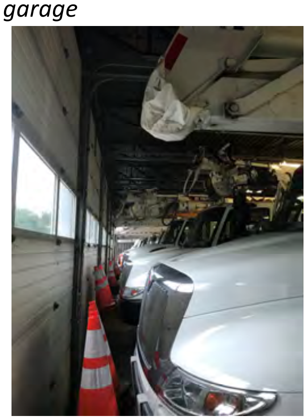
The existing facility consists of a vehicle garage, offices, shops, and warehouse spaces. The office portion of the building is a brick veneer exterior with CMU back-up and a flat membrane roof. The exterior building envelope does not meet the current building codes and lacks proper building insulation. The vehicle garage, shops and warehouse consists of metal siding exterior wall and a flat membrane roof. Built in approximately 1968 the building is antiquated and does not meet the needs of current day operations. Due to the date the building was built construction materials containing asbestos are known to be present. These products would need to be determined and a mitigation plan developed in any of the three options.

Photo of the existing entrance to the building.

Vehicle Garage

The vehicle garage is too small for modern utility trucks currently in use at the facility. The larger vehicles are difficult to drive into the garage due to the low ceiling height and lack of space. It is difficult to work on the trucks in the garage due to the low ceiling height and limited circulation space around the utility trucks. The floor of the garage doesn't have proper drainage and the space lacks proper ventilation. There are 10 large overhead doors, one for each of the utility trucks. This overhead door arrangement is less energy efficient due to the lack of insulation in the doors and the gaps around the opening that allow heat to escape; compared with a layout with only 2 overhead doors (one for inbound and one for outbound) that can be found at Unitil's Concord and Lunenburg DOC facilities.

Photos of the existing vehicle garage



Warehouse and Shops

The warehouse is inadequate for the current inventory needs. The height of the space prevents utilizing larger pallet racks and the floor area inhibits proper circulation with a forklift. The interior is dark and lacks proper ventilation. The space serves several needs including as a storage area, hazardous materials collection area, metering lab/workshop, and meter storage within one space. Over time the spaces has been retrofitted to include a fluids storage area, rubber goods storage, locker area, and other miscellaneous storage areas..

Workshop space is limited to metering. Other workshop activities have been created either outside or created within the warehouse space and are inefficient. .

Photos of the existing warehouse

Exterior Building Envelope
A lack of building insulation and single pane windows makes operating the existing building expensive. Abestos is present in wall materials in the restrooms and server room and due to the age of the building we would anticipate that the caulking around the windows, pipe insulation, and flooring may contain asbestos which would need to be remediated. The roof was replaced in 2008. If a renovation to the building was undertaken we would anticipate having to remove the existing exterior metal panels, windows, and doors and replacing them with products that meet the current building code. We would anticipate leaving the exterior brick façade in place and furring the wall out on the inside to provide insulation.

Photos of existing single pane windows

Building Systems
There is a lack of ventilation in the vehicle garage and warehouse areas. In addition, the building's heating system, which consists of cast iron piping, is deteriorating. The deterioration of these pipes requires constant attention and repair and replacement costs. The electrical systems are inadequate for the building's use and do not meet current codes. There is no sprinkler system within the facility, and though it may not be specifically required, it is a best life safety practice to ensure the safety of employees, as well as, building and inventory assets

Photos of the existing MEP components

PROCON
CONNECT • CREATE • CONSTRUCT

DESIGN OPTION SUMMARIES

OPTION 1 - Renovation

We are confident that any renovation would require bringing the building up to the current building code. This would mean upgrading all the building MEP and life safety systems, updating the structural building systems, and upgrading the exterior building envelope to meet the current energy code. This option would involve utilizing the sub-structure of the building in some capacity and gutting the rest of the building. The site would keep the same layout with the addition of a new well, new septic system, a pond to hold water for the fire suppression system, and upgrading the transformer and pole storage areas.

The cost of this type of extensive renovation and upgrading would be substantial. Based on historical data and our understanding of the project you could anticipate a cost of $265 to $283 per square foot. The facility is approximately 21,000 square feet and we would anticipate the cost of construction to be approximately $5,600,000 to $6,000,000 and could exceed this estimate (see below).

Key Concepts to Keep in Mind:

- There are a significant number of unknowns that could dramatically affect the cost of the project.
- Based on the scope of the project we would expect at least a year or more to get approvals and prepare the design documents. Due to this we have included an escalation cost of 6% into our construction cost assessment numbers above.
- The project will require Unitil's Kensington personnel to relocate for 12 months. We would anticipate a 10 month construction schedule and 1 month at the beginning and end of construction to move out and then back in. During this time Unitil would need to operate out of another facility and the cost of this needs to be accounted for. The size of the building and site, does not lend itself to a phased project while remaining occupied. We typically see spaces leased for two years, and not only one year. It should be noted that during this transition time there is the potential of not providing the level of service your customers expect due to several factors. These factors include the proximity of a leased space to your customers, inadequate space within the new building and the potential for needing to spread employees and equipment out to different locations. We would anticipate that any leased space would also require additional cost for tenant fit-up and may not be able to accommodate outside material storage areas for transformers, poles, wire reels, etc.

  Potential Additional Costs
    - Moving costs, including cost to relocate site items including poles and transformers.
    - Cost of lease

- Cost of lease search
- Legal fees for lease agreements
- Tenant fit-up costs
- Down time to move; potentially additional employee costs such as overtime

- There is a significant amount of wetlands on the site and the project is a prohibited use in the zoning district it is in. Having a well and onsite septic system complicate the process even further. Due to the extended time for permitting and approvals for this project we would anticipate significant legal fees, engineering and site exploration fees to move this project through the state and local approvals process.

  Potential Additional Costs
    - Legal Costs
    - Wetlands specialists
    - Geotechnical costs
    - Civil Engineering costs
    - Wetlands Mitigation Costs
- Soft costs including professional design services are not accounted for in our cost assessment.
- Renovating the existing facility would not make a significant improvement in the overall functionality of Unitil's NH Electric – Seacoast region's Distribution Operations services. The project does not enlarge the building or the site and would not improve the function of day to day operations dramatically. In addition spaces such as utility rooms and bathrooms may need to get larger due to current code requirements and reduce the size of the operational spaces you currently have and that already has very limited meetings and other spaces
- The road outside of the building, Drinkwater Road, floods during large rain events.

Summary – Option 1: The time and cost to renovate the existing building will exceed any gain in operational improvements and less long-term value versus what Unitil would gain in operational improvements and value with a new building. We would anticipate a difficult time obtaining approvals, although out of the three options this option would have the best chance to be granted a special exception from the Zoning Board. In this option Unitil would need to relocate to another facility for 12 months, which may create operational inefficiencies, potentially affecting customer service. The option does not resolve the functional issues currently in the existing facility; including inadequate vehicle storage, poor warehouse space and inadequate space to efficiently run EOC activities.

<u>OPTION 2 – Renovation and Addition</u>

This would mean upgrading all the building MEP and life safety systems, updating the structural building systems, and upgrading the exterior building envelope to meet the current energy code. This option would involve utilizing the sub-structure of the building in some capacity and gutting the rest of the building. The site would keep the same layout with the addition of a new well, new septic system, a pond to hold water for the fire suppression system, and upgrading the transformer and pole storage areas.

Building a 10,000 square foot addition and renovating the existing facility would require bringing the building up to the current building code. This would mean upgrading all the building MEP and life safety systems, updating the structural building systems and upgrading the exterior building envelope to meet the current energy code.

This option would involve renovating the existing building by utilizing the sub-structure of the building in some capacity and gutting the rest of the building. Adding a 10,000 square addition to add offices, CED, OQ Testing and Training, along with expanding other operational spaces would affect the site significantly. The layout of the site would have to be completely redone including providing additional parking, The site would adding a new well, new septic system, a pond to hold water for the fire suppression system, new pole storage, trailer storage, bulk material bins, and providing a new transformer containment storage area(s).

The cost of this type of extensive renovation and addition would be substantial. Based on historical data and our understanding of the project we feel you could anticipate a cost of $269 to $288 per square foot. The existing facility is approximately 21,000 square feet, with a 10,000 square foot addition; we would anticipate the cost of construction to be approximately $8,500,000 to $9,000,000.

Key Concepts to Keep in Mind:

- There are a significant number of unknowns that could dramatically affect the cost of the project.
- . Based on the scope of the project we would expect at least a year or more to get approvals and prepare the design documents. Due to this we have included an escalation cost of 6% into our construction cost assessment numbers above.
- The project will require Unitil's Kensington personnel to relocate for 14 months. We would anticipate a 12 month construction schedule and 1 month at the beginning and end of construction to move out and then back in. During this time Unitil would need to operate out of another facility and the cost of this needs to be accounted for. The size fo the building and site, the same as in Option 1, does not lend itself to an phased project while remaining occupied. We typically see spaces leased for two years, and not only one year. It should be noted that during this transition time there is the potential to not providing the level of service your customers expect due to several factors. These factors include the proximity of a leased space to your customers, inadequate space within the new building and the potential for needing to spread employees and equipment out to different locations. We would anticipate that any leased space would also require additional cost for tenant fit-up and may not be able to accommodate outside material storage areas for transformers, poles, wire reels, etc.
  Potential Additional Costs
    - Moving costs, including cost to relocate site items including poles and transformers.
    - Cost of lease
    - Cost of lease search
    - Legal fees for lease agreements
    - Tenant fit-up costs
    - Down time to move; potentially additional employee costs such as overtime
- There is a significant amount of wetlands on the site and the project is a prohibited use in the zoning district it is in. Having a well and having an onsite septic system complicate the process even further. Due to the extended time for permitting and approvals for this project we would anticipate significant legal fees, engineering and site exploration fees to move this project through the state and local approvals process.
  Potential Additional Costs
    - Legal Costs
    - Wetlands specialists
    - Geotechnical costs
    - Civil Engineering costs
    - Wetlands Mitigation Costs
- Soft costs including professional design services are not accounted for in our cost assessment

- Renovating the existing facility, and adding 10,000 sf, for non-DOC space requirements would not make a significant improvement in the overall functionality of Unitil's NH Electric – Seacoast region's distribution operations services. The project does not enlarge the operations portion of the building or the site and would not improve the function of day to day operations dramatically. In addition spaces such as utility rooms and bathrooms may need to get larger due to current code requirements and reduce the size of the operational spaces you currently have.
  The road outside of the building, Drinkwater Road, floods during large rain events.

Summary – Option 2: The time and cost to renovate the existing building and build a new addition would be substantial and resulting in only a minor improvement in operational efficiencies. We would anticipate a difficult time obtaining approvals, especially with the Town due to the substantial change in use. With this option Unitil would need to relocate to another facility for 14 months, which may create operational inefficiencies, potentially affecting customer service. This options also does not resolve the functional issues currently in the existing facility; including in adequate vehicle storage, poor warehouse space, and inadequate space to efficiently run EOC activities.

OPTION 3 – New Building

This option would involve removing the existing building and construction a new 55,000 square DOC in its place. The building would contain all the operational and functional efficiencies developed during the 2018 & 2019 programming process. The layout of the site would include new parking, a new well, new septic system, a pond to hold water for the fire suppression system, new pole storage area, trailer storage, bulk material bins, and providing onsite transformer containment/storage area(s).

Based on historical data and our understanding of the project the cost for the demolition of the existing building and the construction of the new facility we feel could be done for $234 to $251 per square foot. We would anticipate the cost of construction to be approximately $12,870,000 to $13,805,000.

Key Concepts to Keep in Mind:

- There are a significant number of unknowns that could dramatically affect the cost of the project.
- . Based on the scope of the project we would expect at least a year or more to get approvals and prepare the design documents. Due to this we have included an escalation cost of 6% into our construction cost assessment numbers above.
- The project will require Unitil's Kensington personnel to relocate for 13 months. We would anticipate an 11 month construction schedule and 1 month at the beginning and end of construction to move out and then back in. During this time Unitil would need to operate out of another facility and the cost of these needs to be accounted for. We typically see spaces leased for two years, and not only one year. It should be noted that during this transition time there is the potential to not providing the level of service your customers expect due to several factors. These factors include the proximity of a leased space to your customers, inadequate space within the new building and the potential for needing to spread operations employees and equipment out to different locations. We would anticipate that any leased space would also require additional cost for tenant fit-up.

  Potential Additional Costs
    - Moving costs, including cost to relocate site items including poles and transformers.
    - Cost of lease
    - Cost of lease search
    - Legal fees for lease agreements
    - Tenant fit-up costs

PROCON
CONNECT • CREATE • CONSTRUCT

  - Down time to move; potentially additional employee costs such as overtime
- There is a significant amount of wetlands on the site and the project is a prohibited use in the zoning district it is in. Having a well and having an onsite septic system complicate the process even further. Due to the extended time for permitting and approvals for this project we would anticipate significant legal fees, engineering and site exploration fees to move this project through the state and local approvals process.

  Potential Additional Costs
  - Legal Costs
  - Wetlands specialists
  - Geotechnical costs
  - Civil Engineering costs
  - Wetlands Mitigation Costs
- Soft costs including professional design services are not accounted for in our cost assessment
- The road outside of the building, Drinkwater Road, floods during large rain events impacting services.
- If a new building was to be built onsite it would want to be built in a location similar to where the current facility is. There is the potential to move the building further into the site though there would be a significant increase in the cost for wetland mitigation. If the building moved further into the site it is possible that the existing facility could remain operational during construction.

Summary-Option 3: It should be anticipated that this option would have the greatest difficulty receiving approval from the Town. If constructed it would provide Unitil with a facility that is able to meet the company's needs well into the future.

Overall Summary:
The existing facility, constructed between 1955 and 1962, no longer serves the functional requirements of a 21st century public utility company. The cost of bringing the building up to code is not worth the investment and does not solve the functional issues with the existing building. Proposing a new facility on the existing site poses several challenges, including receiving Town approvals for prohibited use within the district it is in. The recommended solution, in support of Unitil's NH Electric Distribution Operations Center and other company space requirements, is to build a facility on a more suitable site that is properly zoned, has less wetlands impact, and that is located adjacent to a major artery where operations response can be efficiently distributed to Unitil's NH Electric – Seacoast region's Distribution Operations customer base. In addition, A newly constructed facility on a new site will be used and useful for decades longer than a renovation or addition to the existing facility on a site where zoning and wetlands would likely be barriers to project approvals or add significant cost if variances could be acquired.

Attachment

Agel, Jacquie

Subject: FW: Commercial Lease Rates & Availability (Kensington Study)
Attachments: Mimecast Attachment Protection Instructions; 21086863_9 _Batchelder_Road_Brochure.pdf; Portsmouth, 68 NH Ave - Brochure.pdf

From: Margaret O'Brien [mailto:margaret@bowstcommercial.com]
Sent: Wednesday, March 27, 2019 9:48 AM
To: Agel, Jacquie
Subject: RE: Commercial Lease Rates & Availability

Mimecast Attachment Protection has deemed this file to be safe, but always exercise caution when opening files.

Jacquie,
As we discussed, there is currently no inventory for the garage and laydown requirement within your service area. We conducted an exhaustive search initially before landing on the build to suit option in Exeter, NH. The industrial market has gotten even tighter since that effort. The former Vapotherm space at 22 Industrial Drive that we looked at is now leased. The owner of that property did not add on to the building as per his permits.
The attached property in Seabrook is now on the market for sale only. This building is owned by Corium who just relocated to a larger facility and is looking to sell. It would not fit your requirement for garage space and would need extensive renovation to retrofit for Unitil's use.
Outside of your service area, there is one building at 68 New Hampshire Ave at Pease. This space has 6,025 SF of office and 12,500 SF of warehouse/manufacturing space with 3 loading dock doors. Attached is the marketing brochure. This building is currently under contract for sale.

The current market rent for is in the $6.25 to $8.95 PSF NNN range, if we could find a property that fits your requirement.

The lack of inventory coupled with your unique use and layered with looking for an option for Until to occupy for 12 to 14 months presents a very challenging requirement.

Please let me know if you need anything further.

Margaret O'Brien
bow street LLC
111 Bow Street
Portsmouth, NH 03801
Office: 603.427.0700
Cell: 603.828.7245
margaret@bowstcommercial.com

bow street commercial brokerage

From: Agel, Jacquie <agel@unitil.com>
Sent: Tuesday, March 26, 2019 6:16 PM
To: Margaret O'Brien <margaret@bowstcommercial.com>
Subject: Commercial Lease Rates & Availability

Hi Margaret,
As we discussed just now, I'm preparing a document that includes costs for (3) possible options for staying in Kensington. All 3 options include moving out of the space for 12 to 14 months. We'd need approximately 12,000 sf of garage and warehouse space and 6,000 to 8,000 for office space and parking for 50+/- plus an acre or more for material

laydown areas. Please advise re: available inventory (or not) within Unitil's service territory and/or costs for a similar space in the greater seacoast market.
Thank you,
Jacquie

Jacqueline D. Agel
Manager, Fleet & Facilities

Unitil

6 Liberty Lane West
Hampton, NH 03842
T 603.773.6531 M 603.812.7873
www.unitil.com

Attachment

Agel, Jacquie

Subject: FW: Sale of Kensington - $800K

From: Margaret O'Brien [mailto:margaret@bowstcommercial.com]
Sent: Friday, April 05, 2019 10:41 AM
To: Agel, Jacquie
Subject: RE: Sale of Kensington - $800K

Jacquie,
The ballpark estimate for the Kensington facility is in the range of $800,000. This price was based on an “as-is” use both for re use of the industrial building as well as the potential for a residential subdivision or other similar use.
The site, as we know is impacted with a fair amount of wetlands, the majority at the lower half of the site, but also an area at the top of the site. This coupled with the shape of the site, does not leave a large developable site for a developer to subdivide.

Margaret O’Brien
bow street LLC
111 Bow Street
Portsmouth, NH 03801
Office: 603.427.0700
Cell: 603.828.7245
margaret@bowstcommercial.com

From: Agel, Jacquie <agel@unitil.com>
Sent: Thursday, April 4, 2019 4:01 PM
To: Margaret O'Brien <margaret@bowstcommercial.com>
Subject: Sale of Kensington

Hi Margaret,
Although we haven’t finished the ALTA survey for the Kensington facility can you provide a ball park estimate of what we might get for the property.
Would an as is use cost be different than a developers cost who would remove the building and possibly do a subdivision.
My recollection is that out of the 26 acres maybe 10+/- are usable?
Jacquie

Jacqueline D. Agel
Manager, Fleet & Facilities

Unitil

6 Liberty Lane West
Hampton, NH 03842
T 603.773.6531 M 603.812.7873
www.unitil.com

Attachment

PROCON

T 603.623.8811
F 603.623.7250
P.O. Box 4430
Manchester, NH 03108

Unitil Energy Systems, Inc. – Hampton Addition Initial Budget
February 1, 2019

We are providing the below conceptual costs for the construction of a 10,000 square foot, two story addition to your existing Hampton headquaters building. The program is based off of the second floor of the proposed Unitil/NH Electric Operations DOC – Seacoast Region and includes the CED, Engineering Department, OQ Testing, Back-up Field Services & Gas Cont. Room, archive storage, production area, toilets and conference room. The costs for the project are conceptual due to lack of documentation of the existing conditions but based on probable and historic cost data. If the project were to move forward a compresheive existing conditions analysis will need to be completed and a full construction cost be determined. The estimate is based on Spring 2019 pricing, and does not include probable escalation due to a later start date.

Hampton Addition:

Projected Cost Range	**$2,930,000 - $3,100,000**
Cost /Sqft Range	**$293/sqft - $310/sqft**

The projected savings to the Unitil/NH Electric Operations DOC – Seacoast Region project of removing the second floor and associated spaces is as follows:

	Project Cost (1.11.2019)	**Projected Cost Saving**	**Revised Cost:**
Projected Savings (+/-9,700sqft):	**$11,140,507**	**($965,246)**	**$10,175,261**

Project Scope Hampton Addition:
The information below is what we based the cost of the new addition on. Exclusions and items that have not been considered are also stated below.

Building: 65' x 80'; 10,000 sqft, (2) Story Addition onto existing facility proposed at south facing façade

1. Site excavation and backfill
2. Frost wall/slab on grade construction
3. Structural steel with cold formed metal framing exterior wall system
4. Single enclosed stair tower with wall mounted pipe rail
5. Demo of existing façade to accept addition
6. Exterior façade to be brick
7. Flat, single pitch roof system
8. Windows at exterior
9. Wood veneer doors in HM frames
10. Carpet at common and office areas, sheet goods at bathrooms
11. ACT ceiling system throughout
12. Light gauge metal framing and drywall interior partitions
13. Office space to be painted throughout

PROCON

14. Tie into existing sprinkler system
15. (2) single stall bathrooms at each floor +(1) single stall bathroom in CED
16. Kitchenette assumed in CED
17. VAV HVAC system
18. Troffer lighting throughout
19. Standard office wiring for cubicle layout
    a. Electrical considerations included for CED (power/wiring, no equipment)

Additional Items/Not considered

1. Additional upgrades or requirements of the existing building to meet newer building code requirements are excluded.
2. Existing systems assumed to accept additional load
    a. No replacement or upgrading of existing plumbing systems, electrical service, sprinkler, fire alarm,
    b. Existing services assumed already to temp'd to addition
    c. New/existing security/tele/data systems excluded
3. No work assumed in existing building at this time
    a. No consideration for tie backs into existing systems
    b. No Saw cutting/trenching to upgrade or bring new services or lines to area of addition
4. All work to be performed during standard business hours
    a. No off hours/ afterhours work considered
    b. No cost carried for relocation of neighboring personnel
5. Finished access from existing building to addition to be single man door, (1) at each floor
6. No Structural alteration to existing building
7. No Tie in of existing finish
    a. Brick to be cold joint (not toothed), mansard roof not included in addition
8. No site considerations included
    a. Budget based off ideal site conditions, (generally flat, good soils, no blasting)
    b. Loam and seed only, no landscaping, no addition or alteration to existing parking/site drainage/man house/utilities
9. All interior/exterior finish materials carried at budget/allowance until existing materials can be confirmed
10. Does not include MEP closets/fire rated assemblies

Attachment

Agel, Jacquie

From: Michael Lawrence <mlawrence@proconinc.com>
Sent: Tuesday, May 21, 2019 11:41 AM
To: Agel, Jacquie
Subject: UNITIL - Demo costs - Kensington Property

Hi Jacquie,

The costs you have for the three options include the demo costs. Option 3 where we take the whole building down is shows a cost of essentially $300,000, though you should add 10% for general conditions/builders risks/fees, etc. The costs associated with this are below and the abatement costs are an educated guess since there wasn't a study conducted.

02-0000.000 Abatement Cost	21,000.00 SQFT	N/A	$ 7.75	/sqft	$	162
02-0000.000 Building Demo	21,000.00 SQFT	N/A	$ 6.50	/sqft	$	136

Thanks,
Mike

Michael Lawrence
Senior Project Manager - Architecture

PROCON

603.518.2201
mlawrence@proconinc.com
Please visit our new **website**!

Attachment F

Unitil Seacoast Region Facility

Options' Estimates

Created: 4/3/19 jda

Last Update: 6/17/19 jda

Options	Description	SF	Land Cost	Land Sale Estimate	Estimated Soft Costs	Estimated Construction Costs	Estimated Non-Construction Costs [8c]	Temporary DOC Lease Costs [9]: SF	Temporary DOC Lease Costs [9]: Cost PSF +NNN	Temporary DOC Lease Costs [9]: Months	Temporary DOC Lease Costs [9]: Est Cost/Mo	Temporary DOC Lease Costs [9]: Total Occupancy Cost	Lease Fit Up [10]	Move Costs [11]: # of Moves	Move Costs [11]: Estimate	Demolition Estimate [12]	Total Cost	Cost/SF
#1	Kensington DOC Reno (21K sf) + Hampton Addition (10.5K sf)	31,500 [1]	$ - [3]	$ -	$ 1,327,500 [6]	$ 9,100,000 [8a]	$ 1,373,000	21,000	$ 7.60	12	$ 13,300	$ 159,600	$ 250,000	2	$ 175,000	$ -	**$ 12,385,100**	$ 393.18
#2	Kensington DOC Reno (21K sf) & Kensington Addition (10 5K sf)	31,500 [1]	$ - [3]	$ -	$ 885,000 [7]	$ 9,000,000 [8a]	$ 1,373,000	21,000	$ 7.60	14	$ 13,300	$ 186,200	$ 250,000	2	$ 175,000	$ -	**$ 11,869,200**	$ 376.80
#3	Kensington - Build New & Remove Existing	53,940 [2]	$ - [3]	$ -	$ 885,000 [7]	$ 14,005,000 [8a]	$ 1,373,000	21,000	$ 7.60	14	$ 13,300	$ 186,200	$ 250,000	2	$ 175,000	$ 350,000	**$ 17,224,200**	$ 319.32
#4	New - Exeter, NH	53,940 [2]	$ 1,203,000 [4]	$ (800,000) [5]	$ 885,000 [7]	$ 12,562,319 [8b]	$ 1,460,500	0	$ -	$ -	$ -	$ -	$ -	1	$ 87,500	$ -	**$ 15,398,319**	$ 285.47

NOTES:

1. Kensington 21K sf is size of existing bldg. Hampton Addition SF (10.5K): See SF calculations on proposed new Seacoast Region Bldg drawings LE1.1 & LE1.2.

2. Total SF (53,940). See SF calculations on proposed new Seacoast Region Bldg drawings LE1.1 & LE1.2.

3. Land Cost. Land is owned by Unitil.

4. Land Cost. $1M for land + fees (legal, Phase I ESAs, closing costs, current use tax). See Decision Document Attachment G (Purchase & Sales Agreement).

5. Land Sale. Estimate was provided by Commercial Realtor Margaret O'Brien, owner of Bow Street, LLC and is based on her knowledge of the property via recent DRAFT ALTA survey process and the market.

6. Soft Costs. (2) Project Locations (Kensington & Hampton) for this options so additional costs will be incurred for Architect/ID/Security/Electrical/Civil designers and fees for conceptual/schematic/design development services, estimating services, permitting, legal, etc.

7. Soft Costs. (1) Project, same fees as listed above - except for one project location.

8a. Estimated Construction Cost. Provided by PROCON, LLC for all options. See Attachments A (costs for Options 1, 2, and 3) and D (Hampton cost for Option 1) of Decision Document. Plus $200K for Cat IV building construction (See Attachment L).

8b. Estimated Construction Cost. Provided by PROCON. See Attachment J, 4/17/19 "Evolution of Costs to Date". Includes $208K for private road upgrade costs before turn over to Town. Plus $200K for Cat IV building construction (See Attachment L).

8c. Estimated Non-Construction Costs. $1,548,000. Includes; Furniture/Furnishings/Finishes, USC PM Payroll, Warehouse and Shop Material Handling, and IT. Move costs are in a separate column.

9. Temporary DOC Lease. The Kensington building cannot be occupied for Options 1, 2 & 3. The bullet points below are from Realtor Margaret O'Brien

* No inventory exists that would suit requirements for garage and exterior layout areas.
* An exhaustive search for existing commercial buildings was undertaken in 2017/2018 and there was no inventory.
* The commercial market has gotten tighter since the 2017/2018 search.
* There is a property currently in Seabrook that could work but not without extensive and expensive fit up of the space and would not meet requirements for garage space.
* If a property were available in Unitil's Seacoast territory, the current market rent for is in the $6.25 to $8.95 PSF NNN range.
* The lack of inventory coupled with Unitil's unique use and layered w/seeking an option for Until to occupy for 12 to 14 months presents a very challenging requirement
* NNN costs are unknown and are in addition to the lease cost. NNN include property taxes & insurance, and CAM fees. Utilities would be in addition to NNN.

10. Lease Fit Up. Assuming a viable commercial space with a generator, for power back up for normal and EOC operations, was available the estimate to fit up 21,000 SF could be substantially less but could be substantially more. Security alone could cost $50K+.

11. Move Costs. Estimate is based on actual moving costs for relocation of Unitil's MA Gas & Electric DOC in May 2018

12. Demolition. Estimate provided by PROCON, LLC. See Attachment E of Decision Document.

000309

Attachment

PURCHASE AND SALE AGREEMENT

THIS AGREEMENT (this "Agreement") is entered into as of the 15 day of June, 2018 (the "Effective Date"), by and between **GARRISON GLEN** LLC, a New Hampshire limited liability company with a usual place of business at 141 Main Street, Nashua NH 03061, ("Seller"), and **UNITIL ENERGY SYSTEMS, INC.**, or its nominee, a New Hampshire corporation having an address of c/o Unitil, 6 Liberty Lane West, Hampton, NH 03842, ("Purchaser").

1. Purchase and Sale. In consideration of their mutual covenants and agreements set forth in this Agreement, Seller agrees to sell to Purchaser, and Purchaser agrees to purchase from Seller, for the Purchase Price (as hereinafter defined) subject to and on the terms and conditions set forth herein, the following:

(a) A certain parcel of land situated in the Town of Exeter, New Hampshire, presently known as and numbered **20 Continental Drive**, and as described as "Lot 6" in a certain deed recorded with the Rockingham County Registry of Deeds in Book 4404, Page 2738 and shown as the parcel labeled "Lot 6" on the plan entitled "Lot Consolidation/Resubdivision Plan Garrison Glen Corporate Park" prepared by Holden Engineering & Surveying, Inc. dated January 8, 1998 with revisions through July 22, 1998 recorded at the Rockingham County Registry of Deeds as Plan D-26568 (the "Plan"), consisting of approximately 10.75 acres, together with all rights, easements and rights of way appurtenant to **20 Continental Drive** and, approximately one (1) additional acre of land (the "Additional Acre") to be added to **20 Continental Drive,** by way of a lot line adjustment, from the approximately 22.9 acre parcel of land presently known as and numbered **60 Gourmet Place**, Exeter, New Hampshire, and as described as "Lot 8" in a certain deed recorded with the Rockingham County Registry of Deeds in Book 4404, Page 2738, and shown as "Lot 8" on the Plan. The preliminary location and shape of the Additional Acre shall be determined upon the mutual discussion and consent of the Purchaser and the Seller during the Due Diligence Period. The final location of the Additional Acre is subject to (i) further engineered site design and layout by Purchaser of its Intended Use (defined below) of the Real Estate (defined below) during the Permitting Diligence Period and (ii) the review and approval by all local, state and federal authorities with jurisdiction over Purchaser's development of the Real Estate. In the event that the location of the Additional Acre needs to be modified during the Permitting Diligence Period as described in the foregoing sentence, such new location will be subject to the review and approval of the Seller, which approval shall not be unreasonably withheld, conditioned or delayed. (All of the real property described in this Paragraph 1 (a) is collectively referenced in this Agreement as the "Land").

(b) Non-exclusive easement rights in common with others and subject to obligations shared by others in a private way across 60 Gourmet Place as described above (which private way is hereinafter sometimes referred to as "Private Drive') which Private Drive may, in Purchaser's sole discretion, serve as the primary ingress and egress to the Land. The preliminary location and shape of access to the Private Drive, along with the terms and conditions of use of the Private Drive, shall be determined by discussion and consent of the Seller and the Purchaser during the Due Diligence Period. The final location and shape of access to the Private Drive, along with the terms and conditions of use of the Private Drive, is subject to (i) further engineered site design and layout by Purchaser of its Intended Use of the Real Estate during the Permitting Diligence Period and (ii) the review and approval by all local, state and federal authorities with jurisdiction over Purchaser's development of the Real Estate. In the event that the location and shape of access to the Private Drive and/or the terms and conditions of use of the Private Drive need to be modified during the Permitting Diligence Period as described in the foregoing sentence, such new location and/or terms and conditions of use will be subject to the review and approval of the Seller, which approval shall not be unreasonably withheld, conditioned or delayed.

(c) All structures, buildings, improvements and fixtures located on and/or forming a part of the Land, whether above or below ground (collectively, the "Improvements").

(d) Seller's interest in all transferable licenses, approvals, variances, permits and warranties now in effect with respect to the Real Estate and the Improvements, if any, (collectively, the "Permits and Warranties") to the extent the same are in effect at Closing (the Permits and Warranties being referred to herein as the "Intangible Property"), all of which shall be transferred to Purchaser pursuant to an assignment agreement in form and substance acceptable to the Purchaser ("Assignment of Intangible Property").

Attached hereto as **Exhibit A** and made a part of this Agreement is a Plan entitled "Existing Conditions Plan Map 46 Lot 3 Proposed Operations Facility 20 Continental Drive Exeter NH" dated May 11, 2018 which Plan shows the metes and bounds of 20 Continental Drive. Also attached hereto as **Exhibit B** and made a part of this Agreement is a Plan entitled "Sketch Plan Lot Line Relocation 16 May 2018 Scale 1"-120'" which Plan shows the approximate area for consideration as the Additional Acre which is a portion of the Land.

The Land, the Improvements, the "Private Drive" and the Intangible Property are sometimes collectively referred to herein as the "Real Estate".

2. Purchase Price; Earnest Money. The purchase price for the Real Estate shall be **ONE MILLION AND 00/100 DOLLARS ($1,000,000.00)** (the "Purchase Price"), subject to adjustment for prorations as contemplated by Section 9 hereof. The Purchase Price shall be payable as follows:

(a) Upon complete execution of this Agreement and the Escrow Agreement (hereinafter defined), the sum of **THIRTY THOUSAND Dollars ($30,000.00)** shall be tendered as earnest money (the "Earnest Money") in immediately

6/8/2018

available funds in the form of Purchaser's certified check (or wire transfer) made payable to Bow Street LLC ("Escrow Agent"), as escrow agent under this Agreement. The Earnest Money shall be applied to the Purchase Price at Closing or disbursed as otherwise contemplated by this Agreement. The Earnest Money shall be deposited with and held by Escrow Agent in accordance with an Escrow Agreement substantially in the form attached hereto as **Exhibit C**, executed by Seller, Escrow Agent and Purchaser ("Escrow Agreement"). Except in the event of termination of or failure to close this transaction by reason of Purchaser's default, any interest earned on the Earnest Money shall belong to Purchaser and may, at Purchaser's option, be applied to the Purchase Price at the Closing.

(b) Not later than 11:00 a.m., Eastern Daylight Time, on the Closing Date (as hereinafter defined), Purchaser shall pay to the Seller the Purchase Price, plus or minus prorations as hereinafter provided, and subject to application of the Earnest Money, by wire transfer to such bank account as the Seller may designate.

3. Closing.

(a) The consummation of the purchase and sale of the Real Estate ("Closing") shall, subject to the other terms and conditions contained herein, take place at 10:00 a.m. on a date determined by Purchaser which is more than thirty (30) days but less than forty-five (45) days following the expiration of the Permitting Diligence Period, defined below, (the "Closing Date") at the offices of Purchaser's counsel, **PIERCE ATWOOD, LLP**, One New Hampshire Avenue, Suite 350, Portsmouth, NH 03801. Notwithstanding the foregoing, the Closing Date may be extended according to the provisions contained in this Agreement or by written agreement signed by the parties hereto. The terms "Closing" and "Closing Date" shall include any agreed upon extensions thereof.

(b) At the Closing, Seller shall cause to be delivered to Purchaser, the following documents, together with evidence of the authority for the individual(s) executing the same on behalf of Seller:

(1) A good and sufficient Warranty Deed in form and substance customary and usual for the conveyance of commercial real property located in New Hampshire in recordable form properly executed on behalf of Seller, conveying to Purchaser, or to a nominee designated by Purchaser by written notice to Seller at least five (5) business days prior to Closing, the Real Estate and the Improvements in fee simple, subject to the Permitted Exceptions (hereinafter defined);

(2) A duly executed Seller's Title Insurance Affidavit, dated even with the Closing Date, in form and substance satisfactory to the Purchaser and such other documents that the Purchaser's title insurance company may reasonably require in order to issue a title policy in accordance with the provision of this Agreement;

TKM 6/8/2018

(3) An affidavit sworn by an authorized representative of Seller to the effect that Seller is not a "foreign person" as that term is defined in section 1445(f)(3) of the Internal Revenue Code of 1954, as amended, together with so-called "1099S Tax Reporting Forms" for reporting the conveyance contemplated hereby to the Internal Revenue Service;

(4) The Assignment of Intangible Property;

(5) A Closing Statement in form reasonably satisfactory to the parties reflecting the prorations and apportionments of the Purchase Price as required by the terms and provisions contained in this Agreement (the "Closing Statement") and,

(6) Such other documents and instruments as are reasonably necessary in order to effectuate the intent of this Agreement.

(c) At the Closing, Purchaser shall cause to be delivered to Seller the following:

(1) The balance of the Purchase Price, by confirmed wire transfer;

(2) Evidence satisfactory to Seller's counsel, of the identity and authority of the person executing documents on behalf of Purchaser;

(3) Executed originals of the Assignment of Intangible Property and the Closing Statement and,

(4) Such other documents and instruments as are reasonably necessary in order to effectuate the intent of this Agreement.

4. Conditions to Closing. In addition to all other conditions to the completion of the transaction described in this Agreement, Seller and Purchaser agree that the closing of transactions contemplated by this Agreement is subject to the satisfaction, approval or waiver by Purchaser, in Purchaser's sole discretion, of the following conditions:

(a) The Purchaser and its agents, contractors, engineers, surveyors, attorneys, and employees will have a period of time (the "Due Diligence Period"), commencing on the day after the Effective Date and ending on or before 5:00 p.m., on that date which is Ninety (90) days thereafter, to inspect and investigate the Real Estate in order to determine, in Purchaser's sole discretion, whether the Real Estate is suitable for the Purchaser's intended use. Such inspections and investigations may include, without limitation, a survey, environmental site assessments, engineering studies, wetland delineation and soil studies, geotechnical studies, zoning and land use analysis, cost of development and construction analysis, availability of utilities and access, title review and any other investigation the Purchaser may deem necessary. For the purpose of conducting on-site inspections and investigations, Seller agrees to provide Purchaser or its authorized agents, reasonable access to the Real Estate at all reasonable times during the Due

TFM 6/8/2018

Diligence Period upon at least twenty-four (24) hours prior notice to Seller. Notice may be delivered by email or verbally to Seller's representative Thomas F. Monahan. Purchaser hereby agrees to indemnify Seller and to hold Seller and Seller's agents harmless from and against any and all losses, costs, damages, claims or liabilities including, but not limited to, mechanic's and materialmen's liens and attorneys' fees, arising out of Purchaser's access to or entry upon the Real Estate under this Agreement. Purchaser will not, however, be liable under the foregoing indemnity for matters discovered by, as opposed to caused by, Purchaser. Purchaser's indemnity and hold harmless pursuant to this Section 4(a) shall survive the Closing, or earlier termination of this Agreement, for a period of one (1) year.

(b) No later than five (5) business days after the Effective Date, the Seller shall deliver to Purchaser the items set forth on **Exhibit D** attached hereto to the extent they are in Seller's possession or can be reasonably obtained by Seller (the "Seller's Disclosure Documentation"). During the Due Diligence Period, the Purchaser and its agents, contractors, engineers, surveyors, attorneys, and employees will review and inspect the Seller's Disclosure Documentation in order to determine, in Purchaser's sole discretion, whether the Real Estate is suitable for the Purchaser's intended use. Purchaser hereby acknowledges and agrees that the Seller's Disclosure Documentation is being made available to Purchaser for Purchaser's convenience only, and without representation or warranty by Seller of any kind, express or implied.

(c) The Purchaser and its agents, contractors, engineers, surveyors, attorneys, and employees will have a period of time (the "Permitting Diligence Period"), commencing at the end of the Due Diligence Period and ending on or before 5:00 p.m., on that date which is One Hundred Eighty (180) days thereafter, or as may be extended by Purchaser as provided herein, to apply for and obtain any and all necessary licenses, variances, special exceptions, permits and approvals, including without limitation, approvals related to zoning, site plan review, lot line adjustment, wetlands, NH Department of Environmental Services jurisdictional requirements, U.S. Army Corps jurisdictional requirements, building and construction permits, driveway permits and such other approvals and certificates required for Purchaser's intended use of the Real Estate which may include, but is not limited to, administrative offices, training areas, indoor storage/warehouse of utility company related equipment and supplies, outdoor storage, outdoor parking, and indoor parking of utility vehicles ("Intended Use"), from any and all state, local, municipal and federal authorities. Purchaser's obligation to purchase the Real Estate is expressly contingent upon Purchaser procuring during the Permitting Diligence Period all final non-appealable approvals, licensing, and permits as described herein necessary for the Intended Use. Such contingency shall not be deemed satisfied if Purchaser, by virtue of any such approvals, is required to construct off-site improvements or contribute to the cost of off-site improvements or infrastructure or such approvals impose any other conditions which, in Purchaser's sole discretion, are unacceptable to Purchaser, unless Purchaser agrees to any such off-site improvements, contribution, or conditions.

TFM 6/8/2018

In the event any of the conditions set forth in this Section 4 are not satisfied or waived by Purchaser within the Due Diligence Period or the initial Permitting Diligence Period, as applicable, Purchaser may notify Seller and Escrow Agent in writing of the termination of this Agreement prior to expiration of the Due Diligence Period or Permitting Diligence Period, as applicable ("Purchaser's Termination Notice"). In the alternative, the Purchaser may, no later than 10 days prior to the expiration of the initial Permitting Diligence Period, elect to extend the initial Permitting Diligence Period by One Hundred Eighty (180) days in order to obtain all necessary permits, licenses and approvals as described herein. Upon timely receipt of Purchaser's Termination Notice, the Earnest Money shall be refunded to Purchaser by Escrow Agent, both Seller and Purchaser shall be released and discharged from all further obligations under this Agreement to sell and purchase (as applicable) the Real Estate, and neither Seller nor Purchaser shall be subject to any claim by the other for damages of any kind except Purchaser's indemnity and hold harmless agreements as provided in this Agreement. If no Purchaser's Termination Notice has been delivered upon Seller and Escrow Agent within the time periods provided in this Section 4, as may be extended, all conditions to Purchaser's obligations under this Agreement shall be deemed to have been satisfied or waived and Purchaser's obligations to close shall be firm for all purposes under this Agreement. **THE SELLER ACKNOWLEDGES AND AGREES THAT THE PURCHASER MAY TERMINATE THIS AGREEMENT WITHIN THE DUE DILIGENCE PERIOD OR THE PERMITTING DILIGENCE PERIOD, AS MAY BE EXTENDED AS PROVIDED HEREIN, FOR ANY REASON OR NO REASON. IN ADDITION, SELLER ACKNOWLEDGES AND AGREES THAT THE PURCHASER'S PERFORMANCE HEREUNDER IS CONTINGENT UPON PURCHASER OBTAINING ALL SUCH NECESSARY PERMITS AND APPROVALS DESCRIBED HEREIN.**

Notwithstanding anything contained in this Section 4 to the contrary, with respect to any intrusive inspection or test at the Real Estate (e.g., investigation of soil and bedrock conditions, core sampling, soil and groundwater sampling, etc.) desired by Purchaser, the following terms and conditions shall apply: (a) Purchaser must obtain Seller's prior written consent (which consent shall not be unreasonably withheld, conditioned or delayed) as to the scope of the proposed inspection or test and the firm or person performing the same; (b) prior to performing any such inspection or test, Purchaser must deliver to Seller a certificate of insurance to Seller evidencing that Purchaser and its contractors, agents and representatives have in place reasonable amounts of comprehensive general liability insurance and workers compensation insurance for their activities on the Real Estate upon terms and amounts reasonably satisfactory to Seller, covering an accident arising in connection with the presence of Purchaser, its contractors, agents and representatives on the Real Estate, which insurance shall name Seller and such other Seller affiliated parties as Seller may designate as additional insureds thereunder; and (c) Purchaser shall bear the cost of all such inspections or tests and shall be responsible for and act as the generator with respect to any wastes generated by those inspections or tests. Notwithstanding the foregoing, Purchaser shall not be required to indemnify Seller or be liable to Seller for matters discovered by, as opposed to caused by, Purchaser during such intrusive investigations and sampling.

Seller shall cooperate with Purchaser, at no cost to Seller, during the Due Diligence Period, by providing one or more interviews regarding the past and current use of the Real Estate as part of Purchaser's environmental investigation.

TFM 6/8/2018

5. Evidence of Title. The Real Estate is to be conveyed by the Deed referred to in Section 3(b) (1) above. Subject to the terms and provisions contained in this Agreement, said Deed shall convey good, clear record, marketable and insurable title to the Real Estate and the Improvements, free from all liens, municipal betterments, assessments, agreements, and encumbrances except: (a) provisions of building and zoning laws; (b) such real and personal property taxes for the then current tax period as are not yet due and payable on the Closing Date; and (c) any easements, restrictions, covenants, agreements and other matters of record, provided that none of such easements, restrictions, covenants, agreements or other matters of record interfere with or prohibit the Purchaser's intended use of the Real Estate and the Improvements as determined by Purchaser in its sole discretion. In addition, title to the Real Estate and the Improvements shall be insurable for the benefit of Purchaser by a title insurance company licensed to do business in New Hampshire in a fee owner's policy of title insurance, in an amount equal to the Purchase Price, at normal premium rates, in the American Land Title Association form currently in use, subject only to exceptions to title that are acceptable to the Purchaser.

During the Due Diligence Period, Purchaser shall, at its sole cost and expense, satisfy itself that title to the Real Estate and the Improvements is satisfactory to Purchaser and complies in each and every respect with the terms and provisions contained in the first paragraph of this Section 5. If the results of any title examination and/or survey conducted by Purchaser disclose that title to the Real Estate and the Improvements does not comply, Purchaser, on or before expiration of the Due Diligence Period, shall deliver to Seller written notice of Purchaser's objections if any, to such title, describing its objections in reasonable detail (the "Title Objection Notice"). All Purchaser's title objections properly set forth in the Title Objection Notice, together with any title exceptions arising from and after the last Title Objection Notice which are either monetary liens or cause title to the Real Estate and the Improvements to not comply with the requirements described herein, are collectively referred to as "Unpermitted Exceptions". Notwithstanding any term or provision contained in this Agreement to the contrary, any exceptions to title existing prior to the last Title Objection Notice which are not properly and timely set forth in the last Title Objection Notice, shall be conclusively deemed to have been accepted and waived by Purchaser for all purposes under this Agreement and are referred to herein as the "Permitted Exceptions."

Seller shall, prior to Closing, use reasonable efforts to cure any Unpermitted Exceptions properly and timely objected to by Purchaser, provided, however, that anything to the contrary in this Agreement notwithstanding, Seller shall have no obligation hereunder to either: (a) expend any funds and/or to incur any direct or contingent liabilities which, in the aggregate, exceed the sum of Fifty Thousand Dollars ($50,000.00) in order to cause any Unpermitted Exceptions to be cured. Notwithstanding the foregoing, Seller shall, prior to or at Closing, pay or discharge any Unpermitted Exception consisting of a lien or encumbrance voluntarily created or assumed by Seller and not created by or resulting from the acts of Purchaser or any other party not controlled by Seller. By written notice to Purchaser at any time prior to Closing, Seller may extend the Closing Date hereunder by up to thirty (30) days in order to cure any Unpermitted Exceptions which it either elects to cure or is required to cure under the terms and provisions of this Section 5. If Purchaser properly and timely objects to any Unpermitted Exceptions, or if any Unpermitted Exceptions first arising from and after the last Title Objection Notice are found to exist prior to the Closing, and all of the same are not cured by Seller or waived by Purchaser prior to the Closing, as it may be extended, then Purchaser shall, at its election, either: (a) accept

TPM 6/8/2018

title as it then is, without reduction of the Purchase Price; or (b) terminate this Agreement, in which event the Earnest Money shall be returned to Purchaser as Purchaser's sole remedy under this Agreement. So long as Seller has not willfully failed to perform its obligations contained in this Section 5 or elsewhere in this Agreement, Purchaser's termination of this Agreement and return of the Earnest Money shall be its sole and exclusive remedy on account of Seller's default hereunder.

6. Seller Representations. Seller represents and warrants to the Purchaser that as of the date hereof and as of the Closing Date:

(a) Seller is a New Hampshire limited liability company, duly organized, and is in good standing under the laws of the State of New Hampshire, with the power to own real property. Seller has all requisite power and authority to enter into this Agreement and perform its obligations hereunder. The execution and delivery of this Agreement by Seller and the performance of Seller's obligations hereunder have been duly authorized. This Agreement constitutes a valid and binding obligation of Seller, enforceable in accordance with its terms against Seller, subject to bankruptcy, reorganization, insolvency and other similar laws affecting the enforcement of creditors' rights generally and to general principles of equity.

(b) To the knowledge of Seller, as of the date hereof, there are no leases or other agreements for occupancy in effect with respect to the Real Estate, except rights of others including a lease to Gourmet Gift Basket, as it may apply to the Private Drive, a copy of which will be delivered to the Purchaser as part of Seller's Disclosure Documentation;

(c) The execution and delivery of this Agreement and the consummation of the transactions contemplated hereunder on the part of Seller do not and will not (i) violate any applicable law, ordinance, statute, rule, regulation, order, decree or judgment binding upon Seller, or (ii) conflict with or result in the breach of any terms or provisions of, or constitute a default under, or result in the creation or imposition of any lien, charge, or encumbrance upon any of the Real Estate by reason of the terms of any contract, mortgage, lien, lease, agreement, indenture, instrument or judgment to which Seller is a party or which is or purports to be binding upon Seller or which otherwise affects Seller, which will not be discharged, terminated or released at Closing. No action by any federal, state or municipal or other governmental department, commission, board, bureau or instrumentality is necessary to make this Agreement a valid instrument binding upon Seller in accordance with its terms.

(d) Seller has not received any written notice of and to Seller's knowledge there is no pending or contemplated condemnation, eminent domain or similar proceeding or special assessment or betterment assessment with respect to all or any portion of the Real Estate.

(e) No person or other entity has any agreement (oral or written), right or option to acquire any interest in all or any portion of the Real Estate from or through Seller.

TFM 6/8/2018

(f) No lien, other than a lien for real estate taxes not yet due and payable, encumbers or affects title to the Real Estate. There is no claim, action, litigation, arbitration or other proceeding pending or, to Seller's knowledge, threatened against Seller which relates to the Real Estate or the transactions contemplated hereby or which could result in the imposition of a lien against the Real Estate or an action against Purchaser.

(g) There is no action, proceeding or governmental investigation or litigation pending or, to Seller's knowledge, threatened against the Real Estate or Seller, which could, in any manner, adversely affect the transactions contemplated in this agreement or affect the purchase of the Real Estate by Purchaser or the ownership by the Purchaser of the Real Estate after Closing.

(h) Seller is not delinquent in the payment of any tax (real estate or otherwise) bills, utility bills or bills or invoices actually received from any vendor or contractor providing goods or services to the Real Estate, or otherwise arising out of the ownership, operation and/or maintenance of the Real Estate.

(i) Seller has not, and, to Seller's knowledge, no other person or entity has, generated, stored, manufactured, processed, treated, spilled, released or disposed of any Hazardous Substances on the Real Estate, or transported Hazardous Substances to or from the Real Estate, or installed, used, abandoned in place or removed any underground or aboveground storage tanks on the Real Estate or is otherwise aware of the existence of any such tanks. Seller has not caused or to its knowledge permitted to occur, and will not permit to exist, any conditions on the Real Estate which may cause a release of Hazardous Substances at, upon, under or within the Real Estate. Neither Seller nor, to Seller's knowledge, any other party, has been, is or will be involved in operations at or adjacent to the Real Estate, which operations could lead to (1) the imposition of liability on Seller, Purchaser or any other subsequent or former owner of the Real Estate under Environmental Laws, or (2) the creation of a lien on the Real Estate under Environmental Laws. Seller has not received any notice from any governmental authority inquiring about, seeking to investigate, or claiming the existence of any Hazardous Substances on, under or about the Real Estate. "Environmental Laws" shall mean all federal, state or local laws, statutes, common law rulings, ordinances, rules or regulations relating to pollution, contamination, protection of human health or the environment, occupational safety and health or the generation, manufacture, disposal, treatment, release, use, transportation or exposure to chemicals or Hazardous Substances, including, without limitation, the Comprehensive Environmental Response Compensation and Liability Act, as amended; the Resource Conservation and Recovery Act, as amended; the Clean Water Act, as amended; the Toxic Substances Control Act, as amended; the Clean Air Act, as amended; the Occupational Safety and Health Act of 1970, as amended and all state law analogs. "Hazardous Substances" shall mean any product, material, chemical, compound, solid, semi-solid, gas, liquid, waste, pollutant, contaminant or substance whose presence, use, storage, manufacture, disposal, transportation or release, either by itself or in combination with other

TFM 6/8/2018

substances (i) is potentially injurious to the public health, safety or welfare or the environment, (ii) is regulated under any Environmental Laws or by any governmental authority; or (iii) is a basis for liability or potential liability to any governmental authority or third party under any Environmental Laws. Hazardous Substances include, without limitation, hazardous waste, hazardous materials, solid waste, demolition materials, petroleum or petroleum products or fractions thereof, asbestos and asbestos containing materials, polychlorinated biphenyls, molds, pesticides, lead paint and other hazardous or toxic substances, pollutants and contaminants.

(j) To Seller's knowledge, there currently exists no adverse subsurface conditions affecting the Real Estate such as underground mines, landfills, caves or unusual rock formations.

(k) Seller is the owner of the Real Estate.

(i) No petition in bankruptcy (voluntary or otherwise), assignment for the benefit of creditors, or petition seeking reorganization or arrangement or other action under federal or state bankruptcy law is pending or, to the best of Seller's knowledge, threatened against Seller.

For purposes of this Agreement, the phrases "knowledge of Seller", "to the best of Seller's knowledge" or words of like import shall mean the actual, knowledge of Thomas F. Monahan as of the date hereof. Seller shall be presumed to have knowledge of (i) any and all information regarding the real estate contained in the books and records of the Seller and (ii) any fact, matter or circumstance which any such individual, as an ordinary and prudent business person, should have known.

7. Purchaser Representations. Purchaser represents and covenants to Seller that as of the date hereof and as of the Closing Date:

(a) Purchaser is a New Hampshire corporation duly organized, validly existing and in good standing under the laws of the State of New Hampshire. Purchaser has all requisite power and authority to enter into this Agreement and perform its obligations hereunder. The execution and delivery of this Agreement by Purchaser and the performance of Purchaser's obligations hereunder have been duly authorized. This Agreement constitutes a valid and binding obligation of Purchaser, enforceable in accordance with its terms against Purchaser, subject to bankruptcy, reorganization, insolvency and other similar laws affecting the enforcement of creditors' rights generally and to general principles of equity.

(b) The execution and delivery of this Agreement and the consummation of the transactions contemplated hereunder on the part of Purchaser do not and will not (i) violate any applicable law, ordinance, statute, rule, regulation, order, decree or judgment binding upon Purchaser. No action by any federal, state or municipal or other governmental department, commission, board, bureau or instrumentality, except the New Hampshire Public Utilities Commission, is necessary to make this

TFM 6/8/2018

Agreement a valid instrument binding upon Purchaser in accordance with its terms.

(c) No petition in bankruptcy (voluntary or otherwise), assignment for the benefit of creditors, or petition seeking reorganization or arrangement or other action under federal or state bankruptcy law is pending or, to the best of Purchaser's knowledge, threatened against Purchaser.

The provisions of this Section 7 shall survive the delivery of the deed hereunder and shall not merge with any closing documents.

8. Seller's Covenants. Between the date of the execution of this Agreement and the Closing, Seller shall:

(a) Maintain the Real Estate in a commercially reasonable manner. Seller will not, without the prior written approval of Purchaser, make or permit to be made any material change, alteration or modification to any part of the Real Estate;

(b) Maintain commercially reasonable liability insurance coverage with respect to the Real Estate;

(c) Provide to Purchaser, immediately upon the receipt thereof, any and all notices in any manner relating to the Real Estate received by Seller or its agents or representatives from any governmental or quasigovernmental authority, insurance company, or from any other person, entity or party;

(d) Not, without the prior written consent of Purchaser, enter into any new contract or lease affecting the Real Estate or the maintenance, repair or operation thereof; and

(e) Seller acknowledges and agrees that Purchaser will make applications necessary for the development of the Real Estate with governmental agencies and other parties. Seller will cooperate, at no cost to Seller, with Purchaser's efforts to obtain governmental and other approvals for the development of the Real Estate, such as by joining in and executing such applications and documents in providing such information as Purchaser may reasonably request.

9. Prorations and Current Use Tax. The following adjustments to the Purchase Price paid hereunder shall be made between Seller and Purchaser and shall be prorated (as applicable) on a per diem basis up to and including the Closing Date:

(a) All real estate taxes and installments of special assessments or other municipal charges or liens, shall be adjusted as of the Closing Date. If the Closing shall occur before the tax rate or assessed valuation is fixed for the municipal fiscal year in which the closing occurs, the apportionment of real estate taxes shall be upon the basis of the tax rate for the preceding year applied to the most recent assessed valuation of the Real Estate, subject to further and final adjustment when the tax rate and/or assessed valuation is fixed.

TFM 6/8/2018

(b) Utility charges and deposits made by Seller with respect to utilities shall be applied to the benefit of Seller.

(c) A portion of the Real Estate is subject to current use taxation by the Town of Exeter. The parties acknowledge that the Real Estate will come out of current use classification and there will be a land use change tax assessed either after the execution of this Agreement or after the transfer of the Real Estate to the Purchaser. The Seller shall pay fifty percent (50%) of the portion of any land use change tax assessed against the Real Estate, up to a maximum of Ten Percent (10%) of the portion of the Purchase Price allocated to land subject to current use taxation; and the Purchaser shall pay the balance of the land use change tax assessed against the Real Estate, whether the tax is assessed before or after the transfer of the Real Estate to the Purchaser. As of the Effective Date of this Agreement, Seller is negotiating the land use change tax for 20 Continental Drive with the Town of Exeter. Seller shall give Purchaser the opportunity to review any proposed agreement with the Town of Exeter concerning the land use change tax for 20 Continental Drive before such agreement is finalized. Notwithstanding anything contained in this Agreement to the contrary, Purchaser may terminate this Agreement if, in its sole discretion, it is not satisfied with the proposed land use change tax agreement with the Town of Exeter.

(d) The Seller shall pay any other special tax/penalty on the Real Estate, as it becomes due and payable. This provision shall survive the Closing and the Purchaser shall be entitled to receive security, in a form satisfactory to the Purchaser, from the Seller for this commitment, at the time of Closing.

10. Transfer Taxes; Other Costs. Seller and Purchaser shall each pay one-half of the New Hampshire Transfer Tax. Each party shall pay its own attorneys' fees. Purchaser shall pay for any surveys, title examinations and/or title insurance required or desired by Purchaser.

11. Risk of Loss. Except as provided in any indemnity or other provisions of this Agreement, Seller shall bear all risk of loss with respect to the Real Estate until Closing. Seller may, but shall not be required, to maintain insurance on the Real Estate against fire and hazards given that the Real Estate is unimproved land; provided, however, in the event there is a fire or other hazard at the Real Estate that substantially destroys the wooded areas, if any, the Purchaser, in its discretion, may terminate this Agreement, upon written notice to the Seller, in which case the Earnest Money with any interest earned thereon shall be returned to the Purchaser and all other obligations of the parties hereto shall cease and this Agreement shall be void and without recourse to the parties hereto.

12. Condemnation. In the event between the date of this Agreement and the Closing Date, the Real Estate is subject to a potential or actual condemnation or eminent domain proceeding, Purchaser may:

(a) terminate the obligations of the parties hereunder to purchase and sell the Real Estate by written notice to Seller as contemplated by the final paragraph of this Section 12, and upon the exercise of such option by Purchaser the obligations of

TFM 6/8/2018

the parties hereunder to sell or purchase the Real Estate shall become null and void, the Earnest Money shall be returned to Purchaser, and neither party shall have any further liability or obligations hereunder except for Purchaser's indemnification and hold harmless obligations set forth in this Agreement; or

(b) proceed with the Closing, in which event Seller shall assign to Purchaser all of Seller's right, title and interest in and to any award made in connection with such condemnation or eminent domain proceedings, and Purchaser shall receive no credit against or deduct from the Purchase Price incident to such taking.

Seller shall promptly notify Purchaser in writing of any threatened or actual commencement or occurrence of any condemnation or eminent domain proceedings against the Real Estate. In such event, Purchaser shall then notify Seller, within thirty (30) days of Purchaser's receipt or deemed receipt of Seller's notice, whether Purchaser elects to exercise its rights under subparagraph (a) or subparagraph (b) of this Section 12.

13. Default. If the transactions contemplated by this Agreement are not consummated due to a default by Purchaser hereunder, then Seller shall retain the Earnest Money and all interest thereon as liquidated damages and as its sole monetary remedy (it being acknowledged by Purchaser that the actual damages which will be sustained by Seller in such event are not easily quantifiable at this time, and that retention by Seller of the Earnest Money under such circumstances is reasonable under such circumstances, and does not constitute a penalty or forfeiture as concerns Purchaser), except that Seller shall additionally be entitled to exercise any rights or remedies it may have by virtue of any indemnity created or granted herein. If this transaction is not consummated due to a default by Seller hereunder, Purchaser may either: (a) declare this Agreement terminated, in which event the Earnest Money and all interest thereon shall be returned to Purchaser as its sole remedy and all further rights and obligations of the parties hereunder shall cease, other than Purchaser's indemnification and hold harmless obligations set forth at in this Agreement, which shall nonetheless survive; or (b) commence an action for specific performance of Seller's obligations under this Agreement. Under no events or circumstances shall Seller be liable to Purchaser for any indirect or consequential damages under this Agreement.

14. Indemnification.

(a) Seller shall and does hereby indemnify and hold Purchaser, its affiliates, successors and assigns and their officers, directors, employees, agents and shareholders (the "Purchaser Indemnified Parties") harmless from and against all loss, cost, expense, damage, injury, obligation, liability, penalty, fine, suit and settlement including, without limitation, reasonable attorney and consultant fees and expenses, reasonable investigation and laboratory fees and expenses, the costs of remediation as required by any governmental authority, any response costs incurred to any other person or loss of natural resources, including reasonable

TFM 6/8/2018

costs of assessing such injury, court costs and other litigation expenses of whatever kind or nature, known or unknown, contingent or otherwise, arising out of or resulting from any "Pre-Closing Environmental Conditions"; provided, however, that any such indemnification shall not apply to the extent of any losses resulting from the negligence or willful misconduct of the Purchaser or its agents and provided further that this indemnification shall terminate one (1) year after the Closing. "Pre-Closing Environmental Conditions" shall mean any Hazardous Substance present in the soil, groundwater, surface water, sediment or air at the Real Estate that were present prior to the Closing or any migration of any Hazardous Substance in soil, groundwater, surface water, sediment, air, or any of them, before or after the Closing, to a location beyond the boundaries of the Real Estate.

(b) The right of any Purchaser Indemnified Party to indemnification pursuant to this Paragraph 14 will not be affected by any investigation conducted by, for, or on behalf of the Purchaser, or any knowledge acquired (or capable of being acquired) at any time by the Purchaser or any of the Purchaser's contractor's, representatives or agents, whether before or after the execution and delivery of this Agreement or the Closing.

(c) Purchaser shall and does hereby indemnify and hold Seller and its agents harmless from and against all loss, cost, expense, damage, injury, obligation, liability, penalty, fine, suit and settlement including, without limitation, reasonable attorney and consultant fees and expenses, reasonable investigation and laboratory fees and expenses, the costs of remediation as required by any governmental authority, any response costs incurred to any other person or loss of natural resources, including reasonable costs of assessing such injury, court costs and other litigation expenses of whatever kind or nature, known or unknown, contingent or otherwise, arising out of a new release of Hazardous Substances at the Real Estate first occurring on or after the Closing and transfer of ownership of the Real Estate to Purchaser and during the ownership of the Real Estate by Purchaser; provided, however, that any such indemnification shall terminate one (1) year after the Closing and shall not apply to the extent of any losses resulting from the negligence or willful misconduct of the Seller or its agents.

15. Notice. All notices required or permitted hereunder shall be in writing and shall be served on the parties at the following addresses:

If to Seller: Garrison Glen LLC
141 Main Street
Nashua, NH 03061

With a
copy to:

TFM 6/8/2018

If to Purchaser:	Unitil Energy Systems, Inc. 6 Liberty Lane West Hampton, New Hampshire 03842 Attn: Jacquie Agel
With a copy to:	Mark E. Beliveau, Esq. Pierce Atwood, LLP One New Hampshire Avenue, Suite 350 Portsmouth, NH 03801
Escrow Agent:	Bow Street LLC Attn: Margaret O'Brien 111 Bow Street Portsmouth, NH 03801

Any such notices shall be: (a) sent by certified mail, return receipt requested, in which case notice shall be deemed delivered three (3) business days after deposit, postage prepaid in the U.S. mail, (b) sent by a nationally recognized overnight courier, in which case notice shall be deemed delivered one (1) business day after deposit with such courier, or (c) sent by hand delivery, in which case notice shall be deemed delivered on the date of receipt. Notwithstanding the foregoing, copies of notices may be delivered by confirmed and acknowledged electronic mail or facsimile transmission. The above addresses may be changed by written notice to the other party; provided, however, that no notice of a change of address shall be effective until actual receipt of such notice.

16. Governing Law. The validity, meaning and effect of this Agreement shall be determined in accordance with the laws of the State of New Hampshire.

17. Counterparts. This Agreement may be executed in two or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

18. Captions. The captions in this Agreement are inserted for convenience of reference and in no way define, describe or limit the scope or intent of this Agreement or any of the provisions hereof.

19. Assignability. Purchaser may not assign its rights under this Agreement without the prior written consent of Seller, which consent may be granted, withheld, or conditioned in Seller's sole discretion. Notwithstanding the foregoing, Purchaser may, by written notice to Seller at any time at least five (5) business days in advance of Closing, designate a nominee to accept title to the Real Estate at Closing. Such nominee shall be jointly and severally liable for all Purchaser's obligations hereunder.

20. Binding Effect. This Agreement shall be binding upon and inure to the benefit of the parties hereto and their respective legal representatives, successors and permitted assigns.

TFM 6/8/2018

21. Modifications; Waiver. No waiver, modification amendment, discharge or change of this Agreement shall be valid unless the same is in writing and signed by the party against which the enforcement of such modification, waiver, amendment, discharge or change is sought.

22. Entire Agreement. This Agreement contains the entire agreement between the parties relating to the transactions contemplated hereby and all prior or contemporaneous agreements, understandings, representations or statements, oral or written, including, without limitation, the Non-Binding Letter of Intent dated April 3, 2018, are superseded hereby.

23. Partial Invalidity. Any provision of this Agreement which is unenforceable or invalid or the inclusion of which would adversely affect the validity, legality or enforcement of this Agreement shall be of no effect, but all the remaining provisions of this Agreement shall remain in full force and effect.

24. No Third Party Rights. Nothing in this Agreement, express or implied, is intended to confer upon any person, other than the parties hereto and their respective successors and assigns, any rights or remedies under or by reason of this Agreement, nor shall any term or provision in this Agreement impair or diminish any rights or remedies Seller or Purchaser may have against any person not a party hereto, except as expressly stated herein.

25. Broker. Seller and Purchaser represent each to the other that each has had no dealings with any broker, finder or other party concerning Purchaser's purchase of the Real Estate, except Bow Street, LLC (the "Broker"). The Broker represents the Purchaser only in this transaction. The Purchaser shall be responsible for the fee/commission due Bow Street, LLC upon Closing. Seller and Purchaser each hereby agree to indemnify and hold the other harmless from all loss, cost, damage or expense (including reasonable attorney's fees) incurred by the other as a result of their breach of the foregoing representation and warranty. The representations and warranties contained in this Section 25 shall survive the Closing or the termination of this Agreement.

26. Effective Date. For purposes of calculation of all time periods within which Seller or Purchaser must act or respond as herein described, all phrases such as "the date of this Agreement," "the date of execution of this Agreement" or any other like phrase referring to the date of the Agreement, shall mean and refer to the Effective Date of this Agreement as described in the first sentence of page 1 hereof, regardless of whether or not both Seller and Purchaser may or may not have executed this Agreement on such Effective Date.

27. Exclusivity. The Seller agrees that from the Effective Date to the Closing Date or such earlier termination of this Agreement as allowed for herein, the Seller, its agents or representatives may not, directly or indirectly, (i) solicit or encourage any inquiries or proposals for, or enter into any discussions with respect to, the acquisition by any person (other than the Purchaser and its representatives) of any interest in the Real Estate; or (ii) furnish or cause to be furnished any non-public information concerning the Real Estate to any person (other than the Purchaser and its representatives), other than as required by applicable laws and regulations and in each case after prior notice to and consultation with the Purchaser. The Seller and its respective agents and representatives will promptly notify the Purchaser of any inquiry or

TKM 6/8/2018

proposal received by such person with respect to the acquisition by any other person of the Real Estate.

28. No Publicity. The Seller will keep strictly confidential the existence of this Agreement, the contents hereof and will not issue any press release or other public statement without the consent of the Purchaser, except for disclosures required by applicable laws and regulations, in which case, the Seller will consult with the Purchaser and cooperate to the maximum extent possible in advance of such disclosure.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the day and year first above written.

WITNESS:

SELLER:
GARRISON GLEN LLC

Thomas F. Monahan, Manager

PURCHASER:
UNITIL ENERGY SYSTEMS, INC.

By
Thomas P. Meissner, Jr.
President and CEO

BROKER (for the limited purpose of acknowledging the provisions of Section 25 hereof):

BOW STREET LLC

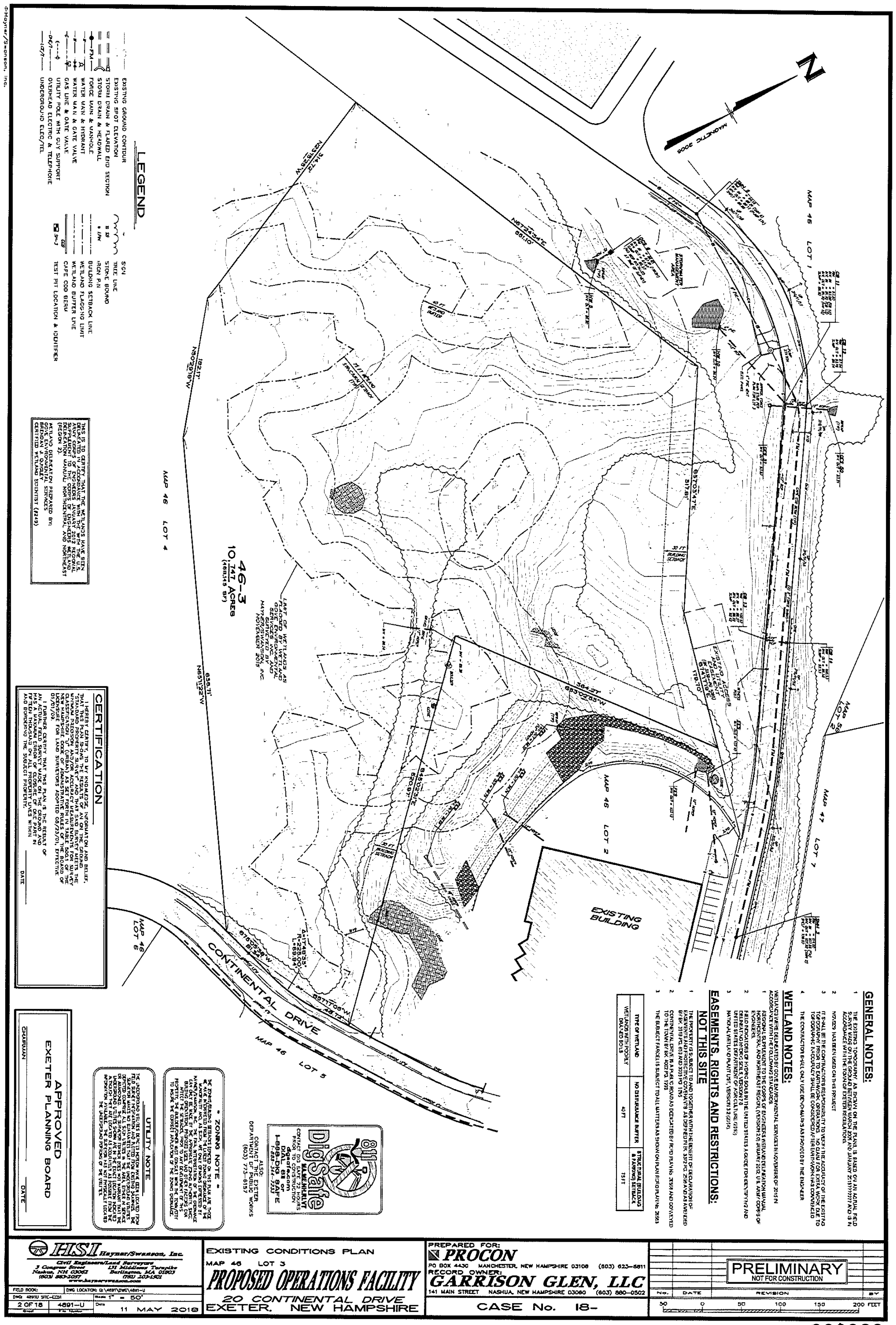
TPM 6/8/2010

Mark Belisimo

By: Margaret O'Brien
Margaret O'Brien, Member

H:\tjleonard\Clients\Monahan, Thomas\Garrison Glen Property Development\Purchase Sale Agreement - Garrison Glen LLC redline WWF 5-21-18.docx

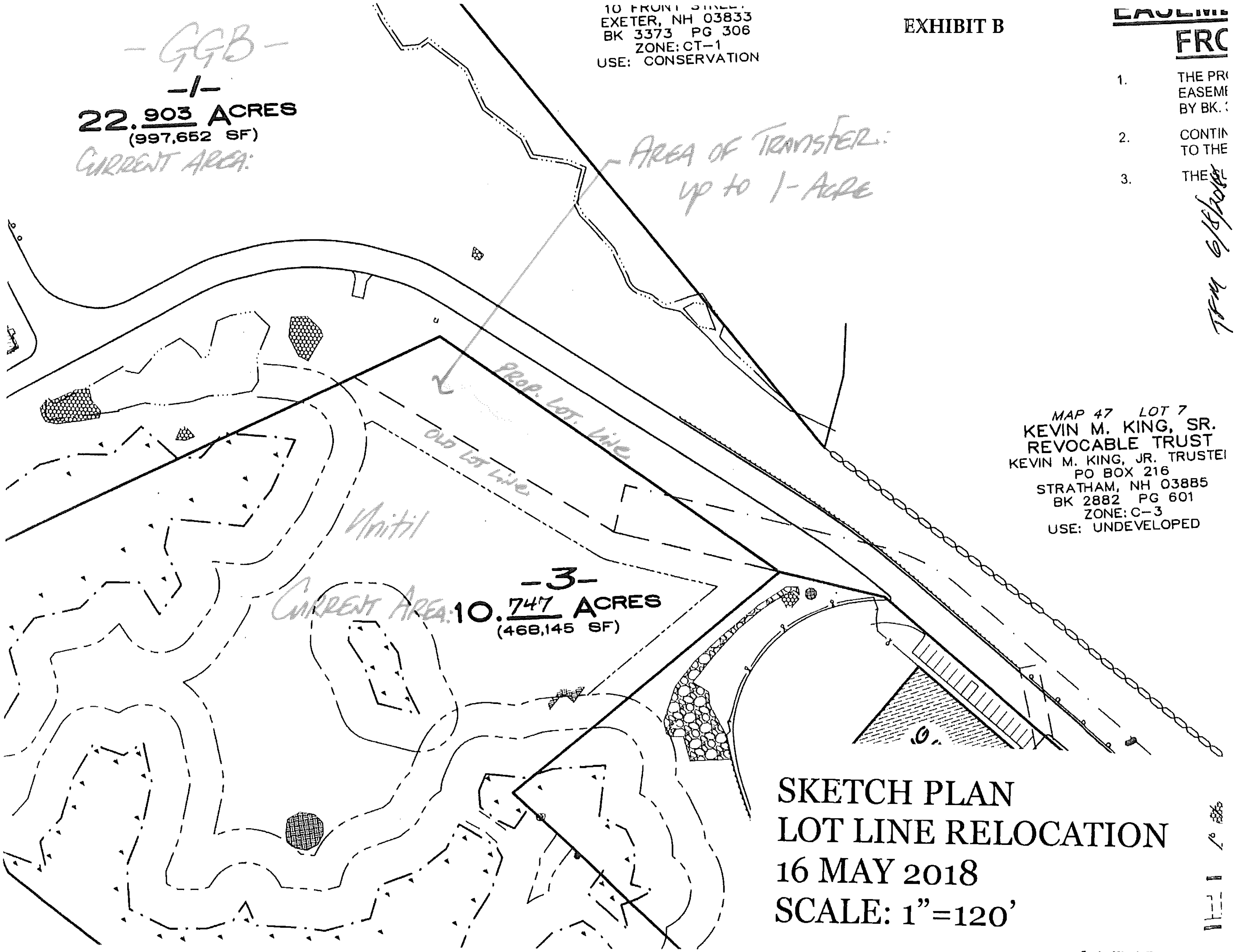
TMM 8/8/2018



TFM 6/8/2018

000328

EXHIBIT B



SKETCH PLAN
LOT LINE RELOCATION
16 MAY 2018
SCALE: 1"=120'

000329

EXHIBIT C

ESCROW AGREEMENT

{W6729671.2}

EXHIBIT D

List of Seller's Disclosure Documentation

1. Copy of an Owner's Policy of Title Insurance, Policy No. A75-0892783 dated December 3, 2004 showing the Seller as Owner of Lot 6 as shown on Plan D-26568 which lot is also known as Map 46, Lot 3 of the Assessor's Maps for the Town of Exeter, New Hampshire and which lot is a apportion of the Real Estate,;

2. Copies of financial data related to the Real Estate, including the most recent real property tax bills, any special assessments, and any correspondence relating thereto, received by Seller in connection with the Real Estate;

3. Copies of any and all engineering studies, wetland studies, topographical studies, and soil boring test results;

4. Copies of any and all existing, proposed or proffered conditions and agreements accepted and agreed to by Seller (or any predecessor in title to Seller if such documents are in the possession of Seller) as a condition to development of the Real Estate;

5. Copies of all environmental reports, studies, permits and all other documents pertaining to any use or presence of Hazardous Substances (as defined in the Agreement) in, on, under or about the Real Estate or pertaining to any other environmental matter with respect to conditions in, on, under or about the Real Estate, or operations and businesses conducted thereon, if any;

6. Copies of all subdivision and site plans, and all approvals, permits and licenses related to the Real Estate;

7. Copies of all leases, service agreements, and contracts of agreements affecting the Real Estate; and

8. Copies of all other documents, instruments and agreements relating to the Real Estate which are reasonably requested in writing by Purchaser.

If Purchaser terminates this Agreement pursuant to any of Purchaser's rights to do so under this Agreement, Purchaser will return to Seller all the documents provided by Seller hereunder.

EXHIBIT C

ESCROW AGREEMENT

THIS AGREEMENT is entered into by and among Garrison Glen LLC ("Seller"), Unitil Energy Systems, Inc. ("Purchaser"), and Bow Street LLC, ("Escrow Holder").

WITNESSETH, WHEREAS

A. Seller and Purchaser have entered into a Purchase and Sale Agreement dated as of June 15, 2018 ("Purchase Agreement") pursuant to which Seller has agreed to sell to Purchaser the real estate and improvements therein described located in Exeter, NH, and Purchaser, subject to the terms of the Purchase Agreement, has agreed to deliver into escrow with Escrow Holder, the sum totaling Thirty Thousand Dollars ($30,000.00) ("Earnest Money"), which Earnest Money is to be held and disbursed by Escrow Holder, or paid directly to Seller, as the case may be, in accordance with the terms and conditions of this Agreement and the Purchase Agreement, which Earnest Money and any interest or earnings thereon shall hereinafter be referred to as the "Fund." Capitalized terms used and not otherwise defined herein shall have the meaning ascribed to such terms in the Purchase Agreement.

B. Purchaser has deposited the Earnest Money with Escrow Holder on June 15, 2018 concurrently with the execution of this Agreement.

C. Purchaser has advised Escrow Holder that Purchaser's taxpayer identification number is 02-0121400

D. Escrow Holder agrees to act as escrow holder to hold, administer, invest and disburse the Fund on the terms and conditions herein set forth.

NOW, THEREFORE, in consideration of the foregoing and in consideration of the mutual covenants of the parties herein contained, and in further consideration of the sum of Ten Dollars ($10.00), which each of the parties acknowledges as adequate and sufficient, the parties hereto agree as follows:

1. Definitions.

All terms used herein, unless otherwise herein defined, shall have the meanings set forth in the Purchase Agreement.

2. Acknowledgment of Receipt.

Escrow Holder hereby acknowledges receipt of the Earnest Money from Purchaser pursuant to the Agreement, consisting of $30,000.00.

3. Administration and Investment of Fund.

Escrow Holder hereby agrees to hold, administer and disburse the Fund pursuant to this Agreement, and in accordance with the Purchase Agreement. Escrow Holder shall deposit the funds in a federally insured financial institution without interest Earned thereon.

4. Termination by Seller or Purchaser.

If at any time hereafter either Seller or Purchaser shall deliver to the other ("Recipient") and to Escrow Holder a written notice (given in accordance with Paragraph 8 hereof) asserting that the party giving the notice ("Notice Party") is entitled to receive and retain the Fund pursuant to the terms of the Purchase Agreement, Escrow Holder shall, not less than ten (10) business days after receipt of such notice, deliver the Fund to Notice Party unless within said period of ten (10) business days Recipient shall give written notice to Escrow Holder and Notice Party that it disputes Notice Party's claim to the Fund, in which case Escrow Holder shall either: (a) retain the Fund until it receives written instructions executed by both Seller and Purchaser as to the disposition and disbursement of the Fund, or until ordered by final court order, decree or judgment, which has not been appealed, to deliver the Fund to a particular party, in which event the Fund shall be delivered in accordance with such notice, instruction, order, decree or judgment; or (b) transfer the Fund either to a party mutually agreeable to Purchaser and Seller to serve as a substitute escrow holder to hold the deposit and such interest pending the resolution of dispute between Purchaser and Seller, or into a court of competent jurisdiction if the parties are unable to agree upon a substitute escrow agent.

In the event Seller or Purchaser notifies Escrow Holder that it is entitled to release of the Fund as hereinabove permitted, Purchaser's or Seller's notice to Escrow Holder shall include a copy of the notice to the Recipient and a statement on which Escrow Holder may rely, that Purchase or Seller has notified the other party that the requesting party is entitled to the Fund.

5. Disbursement at Closing or Termination.

Subject to Paragraph 4 hereof, Escrow Holder shall, at Closing, apply the Fund to the Purchase Price to be paid by Purchaser to Seller, in accordance with the Purchase Agreement. At the Closing, the full amount of the Earnest Money shall be applied to the Purchase Price or disbursed as otherwise contemplated by this Agreement.

6. Escrow Holder.

(a) Escrow Holder shall directly or indirectly hold possession of and keep all of the Fund subject to the terms and conditions of this Agreement, and shall deliver and dispose of the same according to the terms and conditions hereof, and shall deal with the parties hereto in relation to the sums so escrowed fairly and impartially according to the intent of the parties as herein expressed, provided however that Escrow Holder is to be considered as a depository only, shall not be deemed to be a party to any document other than this Agreement, and shall not be responsible or liable in any manner whatsoever for the sufficiency, manner of execution, or validity of any written instructions, certificates or any other documents received by it, nor as to the identity, authority or rights of any persons executing the same. Escrow Holder shall be entitled to rely at all times on instructions given by Seller and/or Purchaser, as the case may be and as required hereunder, without any necessity of verifying the authority therefor. Notices given (i) by counsel to and on behalf of Purchaser, shall be deemed given by Purchaser, and (ii) by counsel to and on behalf of Seller, shall be deemed given by Seller, provided that in each case such notices recite the authority of such counsel to so act.

(b) Escrow Holder shall not at any time be held liable for actions taken or omitted to be taken in good faith and without negligence. Seller and Purchaser agree to save and hold Escrow Holder harmless from any loss and from any claims or demands arising out of its actions hereunder and hereby agree to indemnify Escrow Holder from any claims or demands for losses arising out of its activities hereunder.

(c) It is further understood by Seller and Purchaser that if, as the result of any disagreement between them or adverse demands and claims being made by any of them upon Escrow Holder, or if Escrow Holder otherwise shall become involved in litigation or proceedings with respect to this Agreement or the Purchase Agreement, such parties agree that they, jointly and severally, are and shall be liable to Escrow Holder and shall reimburse Escrow Holder on demand for all costs, expenses and counsel fees it shall incur or be compelled to pay by reason of such litigation.

(d) In taking or omitting to take any action whatsoever hereunder, Escrow Holder shall be protected in relying upon any notice, paper, or other document believed by it to be genuine, or upon evidence deemed by it to be sufficient, and in no event shall Escrow Holder be liable hereunder for any act performed or omitted to be performed by it hereunder in the absence of negligence or bad faith. Escrow Holder may consult with counsel in connection with its duties hereunder and shall be fully protected in any act taken, suffered or permitted by it in good faith and without negligence in accordance with the advice of such counsel.

(e) Purchaser agrees that Escrow Holder shall not, by virtue of its serving as Escrow Agent, be disqualified from representing Purchaser as Broker in connection with this Agreement and/or the Purchase Contract.

7. Term of Agreement.

The term of this Agreement shall be from and after the date of this Agreement as hereinafter set forth to and including the earliest to occur of (i) any of the events set forth in Paragraphs 4, 5 and 6 hereof; (ii) the termination or cancellation of the Purchase Agreement in accordance with its terms; or (iii) the termination hereof by written agreement of the parties hereto.

8. Notices.

Any notices under this Agreement shall be: (a) sent by certified mail, return receipt requested, in which case notice shall be deemed delivered three (3) business days after deposit, postage prepaid in the U.S. mail, (b) sent by a nationally recognized overnight courier, in which case notice shall be deemed delivered one (1) business day after deposit with such courier, or (c) sent by hand delivery, in which case notice shall be deemed delivered on the date of receipt, in each case to the parties at their respective addresses as follows:

If to Seller:	Garrison Glen, LLC 141 Main Street Nashua NH 03061 Attn: Thomas F. Monahan
With a copy to:	Welts, White & Fontaine, P.C. Attn: Thomas J. Leonard, Esq. 29 Factory Street P.O. Box 507 Nashua, NH 03061
If to Purchaser:	Unitil Energy Systems, Inc. 6 Liberty Lane West Hampton, New Hampshire 03842 Attn: Jacquie Agel
With a copy to:	Mark E. Beliveau, Esq. Pierce Atwood, LLP One New Hampshire Avenue, Suite 350 Portsmouth, NH 03801
Escrow Agent:	Bow Street LLC Attn: Margaret O'Brien 11/Bow Street Portsmouth, NH 03801

The above addresses may be changed by written notice to the other party; provided, however, that no notice of a change of address shall be effective until actual receipt of such notice. Courtesy copies of notices are for informational purposes only, and a failure to give or receive copies of any notice shall not be deemed a failure to give notice.

9. Miscellaneous.

(a) This Agreement shall be binding upon and inure to the benefit of the parties hereto and their respective heirs, executors, administrators, representatives, successors and assigns.

(b) This Agreement shall be construed under and governed by the laws of the State of New Hampshire, and, in the event that any provision hereof shall be deemed illegal or unenforceable, said provision shall be severed herefrom and the remainder of this Agreement shall be enforced in accordance with the intentions of the parties as herein expressed.

(c) This Agreement may not be amended or altered except by an instrument in writing executed by all the parties hereto.

(d) This Agreement may be executed in counterparts, all of which taken together shall constitute one agreement.

10. Counterparts.

This Agreement may be executed in two or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

WITNESS WHEREOF, the parties hereto have executed this Agreement as of June ___, 2018. In the event of a conflict between the terms hereof and the terms of the Purchase Agreement, the Purchase Agreement shall govern.

SELLER:

GARRISON GLEN LLC

Witness

______________________ ______________________
Thomas F. Monahan, Manager

PURCHASER:
UNITIL ENERGY SYSTEMS, INC.

______________________ By:______________________
Thomas P. Meissner, Jr.
President and CEO

ESCROW HOLDER:
BOW STREET LLC

______________________ By:______________________
Margaret O'Brien

{W6743357.1}

FIRST AMENDMENT TO PURCHASE AND SALE AGREEMENT

THIS FIRST AMENDMENT TO PURCHASE AND SALE AGREEMENT is dated as of the 5 day of September, 2018, by and between **GARRISON GLEN** LLC, a New Hampshire limited liability company with a usual place of business at 141 Main Street, Nashua NH 03061, ("Seller"), and **UNITIL ENERGY SYSTEMS, INC.**, or its nominee, a New Hampshire corporation having an address of c/o Unitil, 6 Liberty Lane West, Hampton, NH 03842, ("Purchaser").

RECITALS

WHEREAS, by Purchase and Sale Agreement dated June 15, 2018 (the "Agreement") Seller agreed to sell and Purchaser agreed to purchase the "Real Estate" as defined in the Agreement.

WHEREAS, the Seller and Purchaser now wish to amend the Agreement as more particularly described herein.

NOW, THERFORE, in consideration of the mutual covenants, promises and undertakings set forth below, the parties hereto agree as follows:

1. Section 4(a) of the Agreement is hereby amended by increasing the duration of the Due Diligence Period from ninety (90) days to one hundred fifty (150) days. As a result, the Due Diligence Period will now end at 5:00 p.m. on November 12, 2018.

2. Section 9(c) of the Agreement is hereby amended in its entirety and replaced with the following:

> A land use change tax has been assessed against 20 Continental Drive by the Town of Exeter in the amount of Thirty-Seven Thousand Five Hundred ($37,500.00) Dollars (the "Tax"). The Seller and Purchaser shall each pay fifty percent (50%) of the Tax. Purchaser shall deliver its share in the amount of Eighteen Thousand Seven Hundred Fifty ($18,750.00) Dollars to Seller within thirty (30) days of the complete execution of this First Amendment to Purchase and Sale Agreement. The Seller shall be responsible for delivering full payment of the Tax to the Town of Exeter promptly thereafter (if the Tax has not already been paid by Seller) and provide Purchaser with proof of payment. Payment of the Tax to the Town by Seller is a condition precedent to Purchaser's obligation to purchase the Real Estate. If Purchaser timely delivers a Purchaser's Termination Notice to Seller, Seller shall, within ten (10) days of receipt of Purchaser's Termination Notice, reimburse Purchaser for its share of the Tax in the amount of Eighteen Thousand Seven Hundred Fifty ($18,750.00) Dollars.

3. The Agreement, as amended hereby, is ratified and confirmed and is, as of the date hereof, in full force and effect.

{W6863512.1}

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the day and year first above written.

WITNESS:

SELLER:
GARRISON GLEN LLC

Thomas F. Monahan, Manager

PURCHASER:
UNITIL ENERGY SYSTEMS, INC.

By:
Thomas P. Meissner, Jr.
President and CEO

{W6863512.1}

PIERCE ATWOOD LLP

MARK E. BELIVEAU

Pease International Tradeport
1 New Hampshire Ave. #350
Portsmouth, NH 03801

PH 603.373.2002
FX 603.433.6372
mbeliveau@pierceatwood.com
www.pierceatwood.com

Admitted in: NH

SENT BY ELECTRONIC MAIL AND OVERNIGHT MAIL

April 5, 2019

Garrison Glen, LLC
c/o Thomas J. Leonard
Welts, White & Fontaine, PC
29 Factory Street
PO Box 507
Nashua, NH 03061

Re: Garrison Glen, LLC to Unitil Energy Systems, Inc. - Purchase and Sale Agreement dated June 15, 2018

Dear Jay,

Pursuant to the Purchase and Sale Agreement between Garrison Glen, LLC and Unitil Energy Systems, Inc. (Unitil), please accept this letter as written notice of the election of Unitil to extend the initial Permitting Diligence Period by One Hundred Eighty (180) days. The initial Permitting Diligence Period ends on May 11, 2019. With this extension, the Permitting Diligence Period will now end no later than November 7, 2019.

As you know, under the Purchase and Sale Agreement, the Permitting Diligence Period is that period of time that Unitil has to apply for and obtain all of the final and non-appealable permits and approvals for its project. Unitil is making good progress in this regard and is currently before the Exeter planning board for site plan review, lot line adjustment and road dedication. Unitil met with Exeter DPW earlier this week regarding the condition of Gourmet Place in continuation of the effort to have the road approved by the planning board and then approved and accepted by the Exeter Select Board or Town Meeting as a town road.

Please contact me if you have any questions. Thank you.

Very truly yours,

Mark E. Beliveau

MEB/tak

cc: Jacquie Agel, Unitil

Attachment H

New Seacoast Region Facility
Space Allocation Schedule

Level	Area Name	User	Area #	Area
1st	DOC Open Office & Private Offcs	DOC	1a	2,629
1st	Electric Ops Open Office Area	DOC	1a	481
			1a Subtotal:	**3,110**
1st	Warehouse, RRs, Labs, WrkRms	DOC	1b	9,678
1st	Electric Ops RR & Work Rm	DOC	1b	933
			1b Subtotal:	**10,611**
1st	Garage (Includes Storage Areas)	DOC	1c	16,516
1st	Vehicle Wash Bay	DOC	1d	1,196
1st	Locker Rms	DOC	9	1,413
			1c, 1d + 9 Subtotal:	**19,125**
1st	Engineering Lab	USC	6	**194**
1st	Common Areas	DOC	7	5,787
1st	Conf Rm 103	DOC	7	157
			7 Subtotal:	**5,944**
1st	Kitchen & Dng/Mtg Rms & HR (143 sf)	SHARED	9	**2,647**
2nd	CED + CED Mgr	USC	2	**1,111**
2nd	Gas Control & Field Services	USC	3	**271**
2nd	OQ Testing & Training Rms	USC	4	**1,334**
2nd	Eng Offices & File Rm	USC	5	**3,042**
2nd	Common Areas	USC	8	3,256
2nd	Conf Rm 203	USC	8	159
			8 Subtotal:	**3,415**
			Grand Total:	**50,804**

*Common Areas: Rest/Locker Rms, Conf Rms, Production, Corridors, IT Rm, Stairs, Lobbies....

Rentable Area Legend

- 1a DOC office
- 1b Warehouse, labs, Workroom
- 1c Garage
- 1d Wash Bay
- 6 Engineering Lab
- 7 1st Level Common: Rest Rooms, Conf Rms, Production, IT Closet, Corridors, Lobby, Stairs (other?)
- 9 Shared Common: Kitchen & Dng/Mtg Rms (3), Locker Room

Rentable Area Legend

- 2 CED (+Mgr's Office)
- 3 Gas Control and Field Services
- 4 OQ Testing & Training Room
- 5 Engineering Office, include file room
- 8 2nd Level Common: Rest Rooms, Conf Rms, Production area, IT Rm, Corridors, Lobby, Stairs (other?)

	Sq Ft	Split
DOC:	38,790	80.5%
USC:	9,367	19.5%
Subtotal:	**48,157**	**100.0%**
SHARED:	**2,647**	
DOC Allocation of Shared:	2,132	
USC Allocation of Shared:	515	
SHARED Subtotal:	**2,647**	
Grand Total:	**50,804**	
DOC + SHARED:	40,922	
USC + SHARED:	9,882	
Grand Total:	**50,804**	
Total Bldg:	53,940	(From PB Application)
DOC&USC Grand Total:	50,804	
Difference:	**3,136**	
DOC Allocation of Diff:	2,526	80.5%
USC Allocation of Diff:	610	19.5%
DOC:	43,448	
USC:	10,492	
Grand Total:	**53,940**	

000340

http://u-share.unitil.com/sfp/Costs/Authorizations/Project Approval Documents/Attachment H - Space Allocation Schedule

Attachment

Note: Unitil's new Lunenburg, MA DOC was constructed to a

IV

occupancy category. The decision was made to do the same

Unitil Energy Systems, Inc – Occupancy Category

May 30, 2019

The Occupancy Category designates the nature of the occupancy and how it needs to perform under extreme environmental conditions. The different categories signify different design loads for the structure based on flood, wind, snow, earthquake and ice loads. The appropriate reference for this project is IBC 2009 section 1604.5 (Table 1604.5). The table is broken into four categories, with Category I having the least structural loading requirements and Category IV having the most restrictive structural loading requirements. The table below provides a reference for how the types of structures can be designated into which categories.

I	Buildings and other structures that represent a low hazard to human life in the event of failure, including but not limit • Agricultural facilities. • Certain temporary facilities. • Minor storage facilities.
II	Buildings and other structures except those listed in Occupancy Categories I, III and IV
III	Buildings and other structures that represent a substantial hazard to human life in the event of failure, including limited to: • Buildings and other structures whose primary occupancy is public assembly with an occupant load greater than 30 • Buildings and other structures containing elementary school, secondary school or day care facilities with an occupant load greater than 250. • Buildings and other structures containing adult education facilities, such as colleges and universities, with an occupant load greater than 500. • Group I-2 occupancies with an occupant load of 50 or more resident patients but not having surgery or emergency treatment facilities. • Group I-3 occupancies. • Any other occupancy with an occupant load greater than 5,000[a]. • Power-generating stations, water treatment facilities for potable water, waste water treatment facilities and other public utility facilities not included in Occupancy Category IV. • Buildings and other structures not included in Occupancy Category IV containing sufficient quantities of toxic or explosive substances to be dangerous to the public if released.
IV	Buildings and other structures designated as essential facilities, including but not limited to: • Group I-2 occupancies having surgery or emergency treatment facilities. • Fire, rescue, ambulance and police stations and emergency vehicle garages. • Designated earthquake, hurricane or other emergency shelters. • Designated emergency preparedness, communications and operations centers and other facilities required for emergency response. • Power-generating stations and other public utility facilities required as emergency backup facilities for Occupancy Category IV structures. • Structures containing highly toxic materials as defined by Section 307 where the quantity of the material exceeds the maximum allowable quantities of Table 307.1(2). • Aviation control towers, air traffic control centers and emergency aircraft hangars. • Buildings and other structures having critical national defense functions. • Water storage facilities and pump structures required to maintain water pressure for fire suppression.

For purposes of occupant load calculation, occupancies required by Table 1004.1.1 to use gross floor area calculations

In addition to specific loading requirements outlined above, the occupancy category is used for a number of additional purposes, including the determination of importance factor in ASCE 7, the requirements for structural integrity for exit and elevator hoistway enclosures, glazing for wind design, determination of Seismic Design Category and special inspection and structural observation, among other items.

In June of 2013 the Division of Fire Safety issued an informational bulletin to help define Essential Facilities associated with division 1604.5. Below is a portion of that memo. It indicates that a Category 4 facility, an

Essential Facility, is required to have very specific uses that need to remain operational in the event of extreme environmental loading.

	MTL	JWD	Brc 303.01, Brc 307.01	

DESIGNATION of ESSENTIAL FACILITIES and CRITICAL OPERATIONS POWER SYSTEMS (COPS)

ESSENTIAL FACILITIES

The term "Essential Facility" is limited to a reference in the IBC and found in Section 1604.5 as Occupancy Category IV to include very specific uses such as hospitals, fire and police stations designated shelters, critical national defense functions, etc. It is not a reference to a use group type. A definition is also provided that states …remain operational in the event of extreme environmental loading from flood, wind, snow or earthquakes". The sole purpose for this designation in the IBC is to provide for enhanced structural loading factors for wind, seismic ar snow loads.

While the IBC references the Building Official as the person who makes this designation, the code specifically requires that *"This designation would only be made with consideration of broader public policy, as well as emergency preparedness planning within the jurisdiction in question"*. **Prior to making a determination, the Building Official is therefore obligated to take full consideration of input from all applicable federal, state and municipal authorities.**

Costs:

The current structural design for the Seacoast DOC is based on a Category 2 occupancy. PROCON reached out to Canam to determine what the potential impact would be to move from a Category 2 to a Category 4. They indicated that it would be an increase of 10-15% for the steel. This would result in an approximate increase of $150,000. Other trades, building materials, engineering, etc. with related costs for the potential change in a Category 2 to 4 building upgrade have not been determined at this time.

6/17/19 jda: Included $200K to the "Estimated Construction Costs" in Attachment F.

Determining Occupancy Category:

When there are multiple facilities in one geographical region the facilities as a whole should be considered when determining the occupancy category. In the event of one facility going down, could other facilities provide adequate coverage for the region in question? This holistic approach provides a greater understanding of the risk associated with extreme environmental conditions to a regional response and not just a single facility.

In addition, the occupancy category will need to be reviewed by the Building Inspector to confirm whether they interpret the decision in the same manner.

New NH Seacoast Region Facility
Buildings and Land Search Locations Matrix

Prepared: 4/13/17 Margaret O'Brien (Commercial Real Estate Broker)

Sites w/Buildings	Address	Town	BLDG SF	Acres	Asking Price	Cost SF	Notes
#1	22 Industrial Drive	Exeter	65,760	10.2	$ 5,700,000.00	$ 86.68	Unitil: This option was pursued for approximately 1 year on and off but an agreement could not be reached with the owner. Broker: Footprint 58,500 2nd floor 5,942 office 4850 mezzanine storage Total approved SF = 65,760 Owner of property has permits for an additional curb cut, increased parking spaces by 61 spaces to 172 spaces and increase the building footprint by 25,000 SF
#2	239 Walton Road	Seabrook	54,600	26	$ 2,650,000.00	$ 48.53	Unitil: Not a central location in service territory. Pass on this one. Track for a comp Broker: Located next to a elementary school in a residential area. Building is under agreement. Will track sale as a comparable for the Kensington DOC.
#3	185 South Main Street	Newton	11,152	11.42	$ 950,000.00	$ 85.19	Unitil: Not a central location in service territory. Pass on this one. Broker: Sale is subject to Wells Fargo short sale requirements. Site is actually two lots, 10.14 and 1.22 acres.
#4	143/145A Route 125	Plaistow	10,124	Two parcels 18.10 and 1.78	$ 3,500,000.00	$ 345.71	Unitil: Not a central location in service territory. Pass on this one. Higher price range. Broker: Three existing buildings are on the 1.78 acre lot which abuts the 18.10 acre site.
Land Only	**Address**	**Town**	**BLDG SF**	**Acres**	**Asking Price**	**Cost Acre**	**Notes**
#5	Garrison Glen Continental Drive	Exeter	n/a	Three parcels all contiguous 20.69 ,21.12 and 10.75 acres	varies	Ask sale price $125,000 per acre.	Unitil: Entered into a P&S for the 20 Continental Drive parcel in 2018. Purchased land in 2019 following approximately 12 months of due diligence including the permitting process with the Town of Exeter. Unitil: Issued a letter of intent for 19 Continental Drive. A P&S agreement was not reached. Broker: Most recent transaction was for the 22.9 acre site for GiftBaskets.com (now named Gourmet Place). Land owner built to suit for GiftBaskets with a 10 year lease with options. Building approx. 120,000 +/_ SF warehouse/distribution facility. Starting lease rate was $9.75 PSF, NNN.
#6	5 Continental Drive	Exeter	n/a	15.89	undetermined	undetermined	Unitil: TBD. Not on market. Broker: Purchased for $500,000 on 9/29/2014. This parcel was intended to be used to build a home fashions showroom. Owners decided not to build. May be interested in a sale.
#7	Off Holland Way	Exeter	n/a	20.15	$600,000.00	$ 29,776.67	Unitil: Passed on this due to wetlands and building footprint limitations. Broker: Developer bought this excess land with the Tyco buildings on Holland Way. Saxe Investments, Bill Steinberg. Just listed by CBRE site appears to have a large amount of wetlands. Conceptual for a 31,800 SF medical building (footprint approx. 10,000 SF)
#8	Off Holland Way	Exeter	n/a	21.69	$600,000.00	$ 27,662.52	Unitil: Passed on this due to wetlands and building footprint limitations. Broker: Developer bought this excess land with the Tyco buildings on Holland Way. Saxe Investments, Bill Steinberg. Just listed by CBRE site appears to have a large amount of wetlands. Conceptual for a 15,000 SF medical building (footprint approx. 5,000 SF)
#9	319 New Zealand Road	Seabrook	n/a	75	$ 6,500,000.00	$ 86,666.67	Unitil: Passed on this due to non-central location in service territory, land tends to be wet, and close to the coast - concerns about storms. Broker: Former Yankee Dog Track. We can explore the potential of a 10 acre subdivision of the property at the right hand side of the entrance.
#10	Joanne Drive	Plaistow	n/a	25.81	$ 450,000.00	$ 17,435.10	Unitil: Passed on this due to non-central location in service territory. Broker: Zoned general commercial industrial 14 + acres are usable. Pending sale
#11	4 East Way	Kingston	n/a	11.21	$ 988,000.00	$ 88,135.59	Unitil: Passed on this due to location within service territory Broker: Vacant Land - pending sale listed with KW Commercial NE Janet Faulkner
#12	Route 125/Rte 107	Kingston	n/a	16.98	$ 995,000.00	$ 58,598.35	Unitil: Passed on this due to location within service territory Broker: Vacant Land - pending sale listed with The Merrill Bartlett Group Lyne Bartlett Merrill
#13	Route 125/Rte 107	Kingston	n/a	42.18	$ 995,000.00	$ 23,589.38	Unitil: Passed on this due to location within service territory Broker: Vacant Land - pending sale listed with The Merrill Bartlett Group Lyne Bartlett Merrill
#14	231 Route 125	Kingston	n/a	38	$ 695,000.00	$ 18,289.47	Unitil: Passed on this due location within service territory. Broker: Undetermined as to usable acreage. Vacant land - listed with Masiello Group Greg Schena
#15	Route 125	Kingston	n/a	38	$ 695,000.00	$ 18,289.47	Unitil: Passed on this due location within service territory. Broker: Undetermined as to usable acreage. Vacant land - listed with Masiello Group Greg Schena

Sites w/Buildings					Asking	Cost	Notes
#16	266 Route 125	Kingston	n/a	112	undetermined	undetermined	Unitil: Not on market. Broker: Owned by John Wolters. This 170,000 SF industrial building is sited on approx. 25 acres leaving 87 excess acres. Building has been leased long term to Sears Logistics occupying approx. 70,000 SF. Leasing the rest of the space has been historically challenging. Owner may consider a sale of a portion of the excess land and/or of the existing building.
#17	14 Olde Road	Danville	n/a	16.5	$ 495,000.00	$ 30,000.00	Unitil: Passed on this due to non-central location in service territory. Broker: Large flat corner lot at lighted intersection of 111 and 111A. Site is currently an active horse farm. Listed with Doug Martin KW Commercial.
#18	12 Lafayette Road	Hampton Falls	n/a	12.9	undisclosed	undisclosed	Unitil: Passed on this due to location within service territory. Broker: Located on Route 1 in Hampton Falls, this is the former Faro Gardens site. Zoned Business district. Property looks like it has a fair amount of wetland area. It is currently being marketed as a retail or residential redevelopment.

Seacoast Electric Operations
Outage Response Time Comparison
Kensington, NH vs. Exeter, NH

Fault Location By Town - 1/1/2013 to 12/31/2016			
Town	**Number of Incidents**	**Customers Interrupted**	**Customer-Minutes of Interruption**
Hampton	231	35,391	3,150,736
Stratham	195	20,697	1,751,772
Atkinson	175	12,812	1,035,102
Kingston	159	29,797	2,546,096
Seabrook	154	21,056	1,822,288
Plaistow	149	24,535	2,288,286
Exeter	139	35,853	2,532,578
Newton	120	8,533	886,648
East Kingston	98	16,479	1,479,133
Hampton Falls	95	3,743	266,246
Danville	84	7,940	750,343
Kensington	81	5,325	493,997
South Hampton	43	2,038	261,307
Hampstead	4	66	5,381
North Hampton	1	4	302

UES Seacoast
Construction Authorization

AUTH: **191060**
Date: **8/22/2019**
Budgeted Amount: **$5,000,000.00**

Budget Item No:	**GPBE02**	Type:	**Original**
Budget Year:	**2019**	Sequence:	**1**
Description:	**Construction - New DOC Facility**	Status:	**Completed**
Project Supervisor:	**Agel, Jacquie**	Initiated Date:	**8/22/2019 11:47:27 AM**
Crew Days:	**0**	Initiated By:	**Doucette, George**
Start Date:		Finalized Date:	**9/12/2019 9:46:20 AM**
Completion Date:		Finalized By:	**Lydon, Lisa**

APPROVALS

Action Date	Approved	Approver/Title
9/10/2019	YES	**Lydon, Lisa** *Plant Accountant*
9/10/2019	YES	**Bickford, Tressa** *Manager Utility Accounting and Budgeting*
9/10/2019	YES	**Agel, Jacquie** *Manager, Fleet & Facilities*
9/11/2019	YES	**Closson, John** *VP, People, Shared Services & Org. Effectiveness*
9/11/2019	YES	**Bonazoli, John** *Manager Distribution Engineer*
9/11/2019	YES	**Sprague, Kevin** *VP, Engineering*
9/11/2019	YES	**Main, Dan** *Manager of Regulatory Services and Corporate Compliance*
9/12/2019	YES	**Brock, Laurence** *Senior Vice President & Chief Financial Officer*
9/12/2019	YES	**Vaughan, Christine** *SVP, CFO and Treasurer*

ESTIMATED COST SUMMARY

Description	Amount
Total Project Cost:	$15,931,474.00
Less Customer Contribution:	$0.00
Net Authorized Cost:	$15,931,474.00
Retirement:	$0.00
Cost Of Removal:	$0.00
Salvage:	$0.00
CWO Total:	$15,931,474.00

DESCRIPTION/SCOPE

Construct a new NH Seacoast Region Facility, in Exeter NH, to include space for the following business needs; NH Seacoast's Electric Distribution Operations Center (DOC), Business Continuity for Gas Control & Field Services, System Emergency Operating Center (S-EOC), Central Electric Dispatch (CED), OQ Testing, Training, Offices and lab for Electric Engineering Department.

Scope to include:

Preliminary Survey cost including:
- Preconstruction, engineering & design, construction management pre-construction services, geo-tech, civil/survey, environmental survey, legal fees, permitting, insurance, etc.

Construction: site work, utilities (electric, gas, comm, sewer/water), construction to include:
- 53,940 sf +/- sf for office areas, warehouse, enclosed vehicle storage area with a wash bay, etc.
- Bermed outside transformer & other storage
- Outside material laydown areas
- Emergency back-up Generator
- Construction Administration: Construction Manager and engineers & designers field observations, RFIs, Submittals review and other miscellaneous construction phase documentation.
- Project Close Out: Commissioning, As-Builts, etc.
- Furniture/Furnishings/Equipment: Office, warehouse, operations areas, building electronic access control and security systems, and Information Technology infrastructure.
- Move

This is a multi-year project:
Q3 2019 Break ground/begin construction
2020 Completion, Commissioning and Occupancy

JUSTIFICATION

The current Distribution Operations Center (DOC) is 60+ years old and no longer adequately supports the present day operational needs of UES/Seacoast. The current DOC was constructed in the 1950s. Since that time the customer base has grown as has the requirement to stock more materials (inside and out) including transformers and poles. The transformers take up a great deal of space in a stockyard that was designed for operations 60+ years ago when utility trucks were much smaller. The current day line trucks barely fit into the 1950s garage. In addition, this building will solve space constraints at other company facilities, in connection with business continuity for the company's Gas Control, Field Services and Central Electric Dispatch (CED) functions , Electric Engineering department including lab space for functional testing of equipment as well as, provide space for a Prometric certified Operator Qualifications (OQ) testing.

NOTES

Preliminary Survey costs need to be transferred into individual CWO's.

AUTHORIZATION COMMENTS

CWO Summary

CWO	Description	Amount
20192718	Construction - New DOC Facility	$13,681,559.00
20192719	Engineering & Architectural Services	$933,415.00
20192720	Legal . Insurance, Permitting & Misc	$36,500.00
20192721	Internal Project Management	$150,000.00
20192722	Office: Furniture/Equip./Appliances & Furnishings	$825,000.00
20192723	Warehouse & Ops: Equipment & Furnishings	$20,000.00
20192724	IT / Data / Tel / Misc Equipment & Travel	$160,000.00
20192725	Move to 20 Continental Drive & Clean Out of 114 DWR Building	$125,000.00
	Total	$15,931,474.00

UES Seacoast
Construction Authorization

AUTH: **191035**
Date: **2/8/2019**
Budgeted Amount: **$1,200,000.00**

Budget Item No: **GPBE03**
Budget Year: **2019**
Description: **Acquisition of New DOC & Sale of Existing DOC**
Project Supervisor: **Agel, Jacquie**
Crew Days: **0**
Start Date:
Completion Date:

Type: **Original**
Sequence: **1**
Status: **Completed**
Initiated Date: **2/8/2019 2:59:19 PM**
Initiated By: **Doucette, George**
Finalized Date: **3/28/2019 8:34:19 AM**
Finalized By: **Lydon, Lisa**

APPROVALS

Action Date	Approved	Approver/Title
3/1/2019	YES	**Lydon, Lisa** *Plant Accountant*
3/1/2019	YES	**Bickford, Tressa** *Manager Utility Accounting and Budgeting*
3/21/2019	YES	**Agel, Jacquie** *Manager, Fleet & Facilities*
3/22/2019	YES	**Closson, John** *VP, People, Shared Services & Org. Effectiveness*
3/28/2019	YES	**Bonazoli, John** *Manager Distribution Engineer*
3/12/2019	YES	**Sprague, Kevin** *VP, Engineering*
3/20/2019	YES	**Main, Dan** *Manager of Regulatory Services and Corporate Compliance*
3/22/2019	YES	**Vaughan, Christine** *SVP, CFO and Treasurer*
3/21/2019	YES	**Brock, Laurence** *Senior Vice President & Chief Financial Officer*

ESTIMATED COST SUMMARY

Description	Amount
Total Project Cost:	$1,200,000.00
Less Customer Contribution:	$0.00
Net Authorized Cost:	$1,200,000.00
Retirement:	$900,000.00
Cost Of Removal:	$0.00
Salvage:	$0.00
CWO Total:	$1,200,000.00

DESCRIPTION/SCOPE

Purchase land for a new Seacoast DOC facility.

Sale of existing DOC Seacoast facility @ 114 Drinkwater Road, Kensington, NH

Includes preliminary survey and due diligence costs to vet existing building and land acquisition opportunities, as well as, the sale of 114 Drinkwater Rd.

A P&S agreement for the purchase of a parcel of land in Exeter, NH was entered into in June 2018 with approx. 12 months of due diligence prior to closing on the transaction. $1.2M (includes land purchase $1M, closing costs, broker's fee, current use tax, PSI costs)

JUSTIFICATION

The current facility is nearing 70+ years old, windows are original and need to be replaced and the garage height does not allow adequate clearance for new and taller bucket trucks.

NOTES

AUTHORIZATION COMMENTS

CWO Summary

CWO	Description	Amount
20192713	Acquisition of New DOC & Sale of Existing DOC	$0.00
20192714	Acquisition of New DOC	$1,175,000.00
20192715	Sale of Existing DOC	$25,000.00
	Total	$1,200,000.00

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY

OF

KEVIN E. SPRAGUE

EXHIBIT KES-1

New Hampshire Public Utilities Commission

Docket No. DE 21-030

Table of Contents

Exhibits

I. INTRODUCTION

Q. Mr. Sprague, would you please state your name and business address?

A. My name is Kevin E. Sprague. My business address is 6 Liberty Lane West, Hampton, New Hampshire 03842.

Q. What is your position and what are your responsibilities?

A. I am Vice President of Engineering for Unitil Service Corp., which is a subsidiary of Unitil Corporation ("Unitil") that provides managerial, financial, regulatory and engineering services to Unitil's principal utility subsidiaries, including Unitil Energy Systems, Inc. (hereinafter "UES" or the "Company"). In this capacity, I manage all of the Company's engineering functions, including electric engineering, gas engineering, computer-aided design and drafting, Geographic Information Systems ("GIS"), and management of utility-owned land and property.

Q. Please describe your business and educational background.

A. I have been employed by Unitil Service Corp. for approximately 25 years. I was originally hired as an Associate Engineer in the Electric Distribution Engineering group. I have held the positions of Engineer, Distribution Engineer, Manager of Distribution Engineering, Director of Engineering and now Vice President of Engineering. I accepted the Vice President of Engineering position in January of 2019. I hold a Bachelor of Science in Electric Power Engineering from Rensselaer Polytechnic Institute and a Master of Business Administration from the University of New Hampshire.

Q. Do you have any licenses that qualify you to speak to issues related to engineering?

A. Yes. I am a registered Professional Engineer in the State of New Hampshire and the Commonwealth of Massachusetts.

Q. Have you previously testified before the Commission, or other regulatory agencies?

A. Yes, I have testified on previous occasions before the New Hampshire Public Utilities Commission, the Maine Public Utilities Commission and the Massachusetts Department of Public Utilities. Most recently, I have testified in UES' Least Cost Integrated Resource Planning docket DE 20-002. I have also testified in several of UES' annual Reliability Enhancement Program ("REP") and Vegetation Management Program ("VMP") filings, and Grid Modernization related dockets. I also testified in the last base rate case filing by UES in docket DE 16-384.

Q. What is UES's overriding objective for the operation of its electric system?

A. The Company's primary objective is the provision of safe and reliable service for our customers in the most economical manner. We accomplish this objective, in part, with a rigorous annual planning and budgeting process with a focus on the reliability of our system. The costs of projects to improve or maintain reliability, including investment needed to replace aging electric infrastructure, affect other important objectives, such as the Company's efforts to minimize or mitigate electric rate increases to customers.

Q. What is the purpose of your testimony and how is it organized?

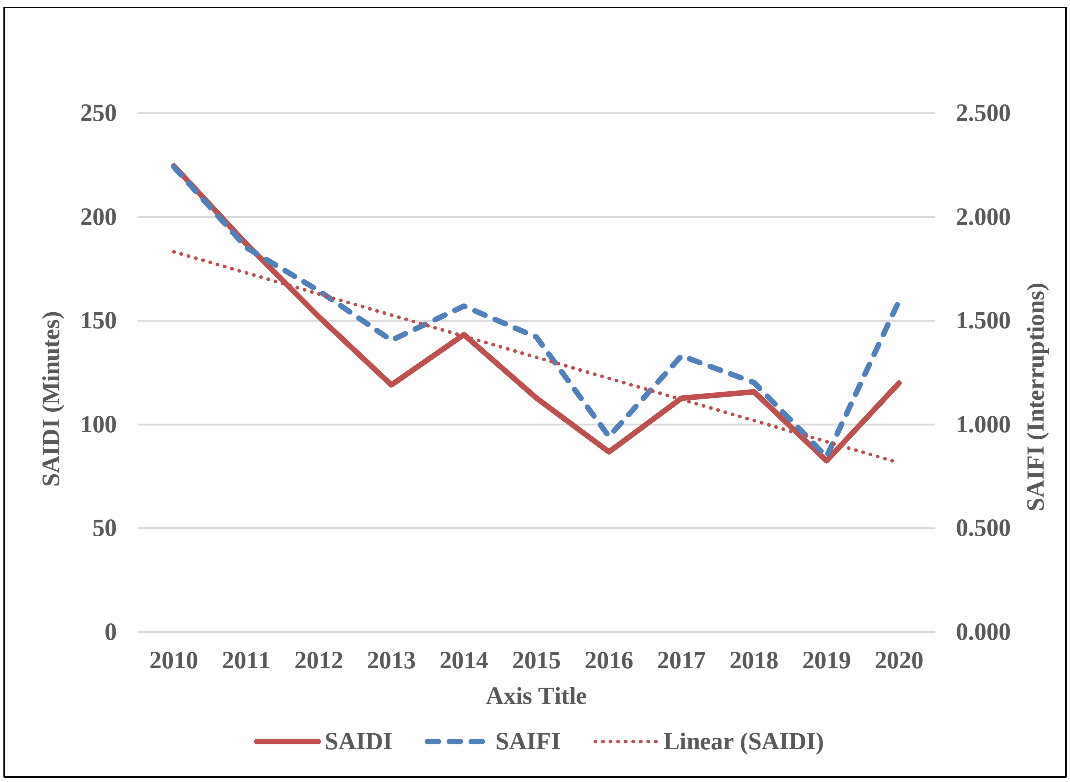
A. The purpose of my testimony is to describe the Company's annual planning and capital budgeting process and the positive effect this approach has had on the reliability of the electric system for our customers. My testimony begins with a description of the Company's reliability performance since the most recent base rate case. Section III describes the Company's approach to capital spending and investment planning including the planning and budgeting process, authorization and control of capital spending and the five year capital budget. This section also identifies several projects that require some additional explanation due to the associated amount of capital spending. Section IV describes the Company's proposed Grid Modernization Plan.

II. RELIABILITY PERFORMANCE

Q. Please describe the reliability performance of the Company?

A. The Company continues to implement an aggressive approach to reliability planning which includes daily, weekly, monthly and annual reliability analyses designed to address overall reliability performance. The Company's reliability performance has shown considerable performance since 2010. Since 2010 the Company's reliability has experienced significant improvement. This is in contrast to the worsening trend in reliability that was identified before the start of the REP program.

Chart 1. UES Reliability Performance



Q. Can you explain the apparent increase in System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") from 2019 to 2020?

A. The Company responded to an unusual number of storm events in 2020, including ten requiring activation of our Emergency Response Plan. The Company restored service quickly and effectively each time. The quick restoration resulted in fewer storm events reaching the exclusionary criteria. Following Tropical Storm Isaias in early August, the Company restored electric service to all customers in under 24 hours. The Company has provided mutual assistance to neighboring utilities eight times in 2020, the most ever in a single year. The Company recently won EEI's Emergency Response (Assistance) Award for the third time in four years.

Q. How does this performance compare to the industry?

A. The Company benchmarks its performance against other utilities. The current industry trend is a worsening reliability over the past several years. The Company's performance in 2020 is in line with the median of the industry. The Company continues to improve performance towards top quartile performance for the industry which tends to be historically be around the mid-80 minute range.

Q. There has been a lot of discussion about electrification in recent years. How will that change customer's view of reliability performance?

A. There has been a great deal of attention provided to decarbonization. The leading solution favors electrification of the heating and transportation sectors. An increase in electrification will make customers more reliant on their electric service for charging their cars and heating their homes. An increase in the number of people working from home also places a greater reliance on electric service. Customer satisfaction will be driven by reliability and the convenience of knowing that customers can rely on their electric company to provide reliable service.

Extended outages due to storm events and rolling blackouts like customers recently experienced in Texas cannot be tolerated in a world that has been electrified. Reliability and resilience will be key to customer satisfaction.

Q. Is the Company proposing to continue its approach to reliability?

A. The Company is proposing to continue to implement the same reliability based analysis and capital improvements as it has done for many years. In addition, some of the projects in the Company's Grid Modernization plan (discussed below) are designed to improve reliability performance.

Q. Is the Company proposing to continue the VMP program?

A. Yes. The testimony of Sara Sankowich describes the success of our vegetation management and storm resiliency programs and the proposal to continue these programs.

III. CAPITAL SPENDING AND INVESTMENT PLANNING

A. PLANNING AND BUDGETING PROCESS

Q. How does the Company plan for needed investments?

A. The annual planning process starts with engineering studies performed by the Company's engineering group. This includes: system studies (34.5kV off road distribution which is used to serve distribution substations and circuits) performed using load flow analysis; joint system planning with Eversource; circuit studies performed using circuit analysis software and protection studies; and area reliability studies. These studies are updated annually with the latest load forecasts at the circuit level and at the transmission level and are employed to identify both short term and long term needs. Engineering planning studies are the first and most important input into the capital planning process.

Q. Please describe the Joint Planning process between UES and Eversource.

A. The goal of the Joint System Planning between UES and Eversource is to develop the most cost effective alternatives for the combined UES and Eversource system. Absent this process, UES and Eversource customers may be subject to more expensive system enhancements due to duplication of facilities between UES and Eversource. This process is intended to promote coordinated planning efforts between UES and Eversource to develop a single "best for all" plan that potentially affects both companies. The objective is to provide a consistent approach for the planning of safe, reliable, cost effective, and efficient expansion and enhancements to each other's local area systems while meeting regulatory and contractual requirements.

By agreement, this process establishes a Joint Planning Committee of Eversource and UES representatives. This committee meets several times on an annual schedule to bring all parties together to coordinate each company's individual plans. The committee considers the application of consistent planning criteria using agreed upon system data; the total cost of planned additions, including internal costs of each utility; the reliability impact of planned additions and modifications; operational considerations, system losses, and maintenance costs; technical considerations for standardized designs and equipment; and the intent of the wholesale supply contract.

Q. Please describe the annual budget process and explain how needs are identified and prioritized as part of this process.

A. As described above, the engineering group identifies the need for system improvement and reliability projects. Operations personnel identify the need for condition replacements based on inspection and maintenance programs. Budgets are constructed using a "bottom up" process each year with input from dozens of employees from engineering, operations, information technology and facilities. Technical and managerial personnel with responsibility for planning, designing, operating and maintaining the electric delivery system are responsible for identifying needs and developing cost-effective solutions. A multistep process is used to budget hundreds of individual projects, and to then prioritize needs and determine which projects are essential to meet our objective of safe and reliable service for our customers. Projects are also proposed that may not be essential, but which represent an improvement or enhancement to existing systems or capabilities, including projects to improve reliability, replace old or obsolete equipment, and projects with a defined economic payback.

Q. How does the Company ensure projects are appropriately specified, estimated and prioritized?

A. In advance of the budget cycle each year, instructions are provided to all budget managers and other contributors that define expectations for the proper development and justification of projects. These instructions ensure that individual budget items are well defined, estimated and justified, and ensure accurate and consistent entry into the budget system. Comparative analysis of competing project costs is completed to identify the most economical solution. The goal of this process is to streamline the review and approval process. Specifically, each submitted project is expected to meet the following requirements:

- Each project must have a well-defined project scope, which fully describes the project and the extent of work to be undertaken.
- Each project must also have a detailed justification that describes the need for the project, including quantitative analysis where possible.

In general, only projects that are well-defined and appropriately justified are included in the budget. Project entries intended to be "place holders" for undefined plans or needs are not accepted. This allows management to efficiently and effectively review priorities and spending, and ensure an appropriate level of funding for important projects.

Q. Please describe how individual projects are categorized within the budget.

A. First of all, the UES capital budget is separated by operating location: UES Capital and UES Seacoast. This provides an additional level of detail used during the management review of the budget. In addition, each project is classified into one of seven categories, which include substation, distribution, annual requirements, transportation, structures and general equipment. Each category is further broken down into subcategories such as overhead extensions, underground extensions, street light projects, telephone company requests, line relocations (highway projects), and reliability projects. Blanket authorizations for annual requirements are broken down into subcategories for T&D improvements, new customer additions, outdoor lighting, emergency & storm restoration, billable work, transformers, meters, and water heater replacements.

Q. How are projects prioritized within the budget?

A. In addition to being appropriately categorized, and having a well-defined scope, justification and cost estimate, all projects in the capital budget are also assigned one of three priorities, defined as follows:

Priority 1: Essential for the Company to meet its service obligation to customers, including the provision of safe and reliable service. Included are projects to address critical constraints such as load and voltage where they jeopardize the Company's ability to distribute electricity, activities to restore service during following emergencies, and construction required to serve new customer load. All projects in this category are considered non-discretionary.

Priority 2: Includes projects that are essential for the Company to perform business activities in the required manner including regulatory or legal requirements, intercompany operating agreements, and supporting facilities, equipment, and vehicles. These projects and activities are also considered to be non-discretionary, though there may be discretion as to timing.

Priority 3: Includes projects and activities that are considered an improvement or enhancement to existing systems or capabilities. These projects are considered to varying degrees to be discretionary.

Q. How is all this information reviewed and validated in developing a final budget

compilation?

A. As budgets are compiled and submitted for review and approval, the budgets are reviewed project-by-project, line-by-line, and category-by-category in a series of meetings held with all applicable budget managers and contributors. Each project is reviewed to ensure that it has been appropriately categorized and prioritized within the budget, and to ensure complete documentation of scope, justification and cost estimates have been provided. Categories of spending, including annual requirements, are scrutinized to ensure the budgeted spending levels are appropriate based on historic spending levels and current assumptions, and adjustments (if needed) are made to ensure budgeted spending levels are appropriate. Priorities are reviewed to ensure all projects have complete justification. Projects without adequate justification are removed or deferred as appropriate. Once a well-prepared budget has been validated and fully vetted, it is advanced through the formal review process for final approval.

Q. How does the Company optimize cost-to-benefit decisions with regard to replacement of aging facilities?

A. The capital planning and budgeting process provides the structure and discipline to carefully evaluate, prioritize and approve those projects that offer the most cost-effective solutions to improve reliability or address significant risks, while also identifying and addressing aging or obsolete facilities. As noted above, budgets are established through a "bottom-up" process each year, with input from dozens of engineering and operations employees. Hundreds of individual projects are scoped, estimated, justified and then prioritized to determine which projects are required to ensure a safe and reliable system for our customers.

B. AUTHORIZATION AND CONTROL OF CAPITAL SPENDING

Q. How does the Company approve, authorize and control spending to ensure the reasonableness and prudence of capital additions?

A. There are several layers of controls on spending. First, and perhaps most important, is the budget process. The capital budget represents the culmination of a lengthy planning process to identify and prioritize important needs, while ensuring that projects submitted for approval are the most cost effective solutions to address identified needs and are estimated appropriately. The budget proceeds through several rounds of review at multiple levels of the organization before concluding with review and approval by executive management, and by the Company's Board of Directors.

Q. Are there other controls over budgeted spending on capital additions?

A. Yes. After the budget is approved, each project within the budget must be further authorized before spending can occur. This is a second step in the approval process, and occurs on a project-by-project basis. A construction authorization must be prepared and submitted for approval for each planned expenditure and each project in the budget, even though the budget has already been approved. Each authorization must be fully approved prior to the commencement of any work, except where an unforeseen emergency occurs that requires the work to be completed to ensure public safety or restore service to customers, in which case the authorization can be completed immediately following the work.

C. FIVE YEAR CAPITAL BUDGET

Q. Has the Company completed the capital planning and budgeting process for 2021 through 2025?

A. Yes. The Table 1 below is the Company's most recent five-year budget for electric projects over the period 2021 to 2025.

Table 1 – 2021-2025 Capital Budget Forecast

Budget Category	**5-Year Budget Forecast**				
Annual Requirements Blankets	**2021**	**2022**	**2023**	**2024**	**2025**
T&D Improvements	$ 2,878,068	$ 2,895,380	$ 3,415,493	$ 3,444,473	$ 3,622,165
New Customer Additions	957,175	983,925	1,187,145	1,206,173	1,286,522
Outdoor Lighting	267,712	281,423	342,710	342,701	359,628
Emergency & Storm Restoration	1,339,224	1,354,155	1,590,379	1,597,322	1,683,570
Billable work	676,909	683,558	809,010	812,547	857,620
Transformers	2,434,392	2,582,342	2,824,038	2,902,620	3,054,949
Meters	1,466,771	1,547,410	1,763,253	1,787,365	1,852,832
Sub-Totals:	**$ 10,020,251**	**$ 10,328,193**	**$ 11,932,028**	**$ 12,093,201**	**$ 12,717,286**
Distribution					
Overhead Line Extensions	115,015	116,398	148,732	150,558	162,610
Underground Line Extensions	966,920	994,010	1,248,444	1,266,319	1,366,936
Street Light Projects	4,657	4,737	5,637	5,625	5,929
Telephone Company Requests	13,365	18,985	22,665	22,580	23,788
Highway Projects	318,584	297,812	352,591	1,012,579	1,043,251
Distribution Pole Replacements	1,551,171	1,809,384	2,153,189	2,214,972	2,334,567
Specific Projects: Distribution	12,191,099	13,911,248	11,050,740	14,035,294	15,819,016
Sub-Totals:	**$ 15,160,811**	**$ 17,152,574**	**$ 14,981,998**	**$ 18,707,927**	**$ 20,756,097**
Substation					
Specific Projects: Substation	1,699,762	5,415,393	6,420,793	3,693,529	4,797,465
Sub-Totals:	**$ 1,699,762**	**$ 5,415,393**	**$ 6,420,793**	**$ 3,693,529**	**$ 4,797,465**
Communications	**$ 3,872,953**	**$ 4,178,905**	**$ 3,197,467**	**$ 3,051,599**	**$ 2,712,445**
Tools, Shop, Garage	**$ 214,500**	**$ 194,500**	**$ 126,700**	**$ 127,900**	**$ 127,900**

Laboratory	**$ 14,000**	**$ 14,000**	**$ 14,000**	**$ 14,000**	**$ 14,000**
Office	**$ 4,000**	**$ 7,000**	**$ 7,000**	**$ 7,000**	**$ 7,000**
Structures	**$ 600,000**	**$ 236,000**	**$ 298,000**	**$ 458,000**	**$ 333,000**
Distribution Totals:	**$ 31,586,277**	**$ 37,526,565**	**$ 36,977,986**	**$ 38,153,156**	**$ 41,465,193**

Q. What is included in the category for "Annual Requirements Blankets"?

A. This category includes blanket authorizations for categories of projects where each individual project is small in value (under $30,000) except for small equipment and general purchases (which are under $4,000) and cannot be individually anticipated at budget time. As I previously explained, these projects are budgeted and authorized under a single blanket authorization representing the anticipated aggregate level of spending. The categories are generally self-explanatory. For example, distribution improvements include: minor upgrades and replacements and repairs to the distribution system; new customer additions consisting of new customer requests for service, including new services and small line extensions; outdoor lighting, which includes repairs and replacements of existing street lights and customer lighting fixtures; emergency and storm restoration, which includes capital repairs and replacements required to restore service to customers following storms or outages; billable work, which includes customer projects, pole accidents, cable TV projects and other projects where all or a portion of the work is billable; and, lastly, the purchase of transformers and meters.

Q. What is in the category for "Distribution"?

A. These projects are individually authorized projects involving capital additions where the value of the project exceeds the maximum threshold allowed under blanket authorizations. The projects are generally self-explanatory. For example, overhead and underground line extensions are new extensions of primary facilities required to provide service to customers; street light projects are new projects to add street lighting; telephone company requests include pole replacements and relocations required under our intercompany agreements with Verizon; highway projects are typically line relocations driven by state or municipal roadway projects; distribution and sub-transmission poles replacements include costs associated with replacing poles that failed inspection during the Company's 10-year pole inspection program; and, specific projects are all other projects in excess of $20,000 that are identified by engineering or others that are needed to meet service obligations.

Q. What is included under the category "Substations"?

A. These are individually-authorized projects involving projects and capital additions to distribution substations. Each project is individually budgeted and authorized. The projects are typically identified by engineering, though the projects may also be identified as the result of inspection and maintenance activities.

Q. What are included under the remaining categories?

A. Communications includes additions and replacements of communication-related equipment such as Supervisory Control and Data Acquisition ("SCADA"), radio systems for field communications, and communication equipment for the Company's Advanced Metering Infrastructure ("AMI") system; tools, shop, and garage includes most tools and test equipment used by electrical workers in the performance of their job; laboratory includes test equipment used to test meters and other devices; office includes furniture and office equipment, including normal additions and replacements; and structures includes upgrades and improvements to the Company's buildings, including the Company's operations center building.

Q. Can you explain where the Company expects to invest most of its capital spending in the subsequent five years?

A. Yes. Table 2 below categorizes the five-year capital budget (in dollars) into two primary categories: Customer Expansion (addition of new customers and new load) and Non-Customer Expansion (no new load added to support the investment).

Table 2 – Forecast Customer Expansion and
Non-Customer Expansion Capital Spending 2021 - 2025

	Capital Budget Spending				
	Forecast				
Electric Category	**2021**	**2022**	**2023**	**2024**	**2025**
Growth					
Customer Additions (C)	5,060,266	5,226,172	6,175,383	6,307,286	6,680,272
Subtotal Growth	**5,060,266**	**5,226,172**	**6,175,383**	**6,307,286**	**6,680,272**
Non-Growth					
Reliability (R)	1,177,285	750,000	750,000	821,457	750,000
Maintenance Replacement (M)	16,548,634	15,375,776	11,222,996	11,209,592	10,551,594

Mandated (H)	318,584	297,812	352,591	1,012,579	1,043,251
System Improvement (I)	2,831,181	5,827,249	7,263,344	6,863,031	8,522,006
Grid Modernization (G)	0	4,979,977	7,304,037	8,013,500	10,450,675
Other (O)	5,650,327	5,069,579	3,909,635	3,925,711	3,467,395
Subtotal Non-Growth	**26,526,011**	**32,300,393**	**30,802,603**	**31,845,870**	**34,784,921**
Total	**31,586,277**	**37,526,565**	**36,977,986**	**38,153,156**	**41,465,193**

% Growth	16%	14%	17%	17%	16%
% Non-Growth	84%	86%	83%	83%	84%

Q. Please describe the way in which you have categorized this capital budget?

A. The table above has been categorized into customer expansion (addition of new customers resulting in revenue producing projects) and non-customer expansion (non-revenue producing) projects.

Customer expansion projects include: new customer services, new customer transformer purchases, new customer meter purchases, overhead line extensions and underground line extensions. These projects are directly related to adding new customers and new load to the system.

The non-customer expansion related category is broken down into reliability, maintenance replacement, mandated, system improvements and other projects. I can explain the types of projects that make up these categories:

Reliability – Projects where the primary justification is to improve reliability (i.e. reduce customer minutes of outage time and/or reduce customer interruptions) such as: distribution automation, recloser additions, spacer cable, adding fusing locations, circuit reconfiguration to reduce outage size, circuit ties.

Maintenance Replacement – Normal replacement of aged equipment such as: distribution pole replacement, distribution improvements, outdoor lighting, emergency and storm restoration, billable work, meter replacements, underground cable replacement, and equipment replacement.

Mandated – Projects necessary to perform assigned business functions in required manner including regulator or legal requirements, intercompany operating agreements and related facilities such as: highway relocation projects, telephone company requests, and third party attachments.

System Improvement – Projects required to address engineering planning constraints such as overloads and voltage problems which violate planning criteria such as: new system supply substations, transformer replacements, voltage regulation projects, reconductoring, and stepdown transformer replacements.

Grid Modernization – These are projects that the Company is proposing within its Grid Modernization Plan. Typical projects in this category consist of (but are not limited to) data sharing, field area network, advanced distribution management system, distributed energy resource management system, SCADA, volt-var optimization, and electric vehicle ("EV") make ready program, in addition to other projects. These projects are discussed in further detail later in this testimony and within the Company's Grid Modernization Plan provided as Exhibit KES-3.

Other – All other projects that do not fit into the categories above such as: equipment and tools, communication projects, office furniture, structure projects, software, and substation modifications.

Q. Can you provide the same table as provided in Table 2 but for actual spending from 2016-2020?

A. Yes. Table 3 below categorizes actual spending from 2016-2020.

Table 3 – Actual Customer Expansion and
Non-Customer Expansion Capital Spending 2016 – 2020

	Actual				
Electric Category	**2016**	**2017**	**2018**	**2019**	**2020**
Growth					
Customer Additions (C)	4,030,800	4,496,900	5,924,000	5,450,400	5,682,300
Subtotal Growth	**4,030,800**	**4,496,900**	**5,924,000**	**5,450,400**	**5,682,300**
Non-Growth					
Reliability (R)	346,100	667,000	740,000	920,500	867,600
Maintenance Replacement (M)	6,359,800	8,823,800	8,617,600	11,149,200	9,048,800
Mandated (H)	1,361,200	154,900	582,400	23,500	333,600
System Improvement (I)	10,692,900	6,106,700	967,900	4,509,900	5,629,400
Grid Modernization (G)		0	0	0	0
Other (O)	396,900	3,500,100	1,455,200	7,015,300	15,684,100
Subtotal Non-Growth	**19,156,900**	**19,252,500**	**12,363,100**	**23,618,400**	**31,563,500**
Total	**23,187,700**	**23,749,400**	**18,287,100**	**29,068,800**	**37,245,800**

% Growth	17%	19%	32%	19%	15%
% Non-Growth	83%	81%	68%	81%	85%

Q. Can you describe the breakdown between customer expansion related and non-customer expansion related capital spending?

A. Yes. As shown in tables 2 and 3 above, the average annual percentage of spending on customer expansion is virtually identical over both the historic five-year period and the future five-year period with 2018 being the one outlier of a year. In 2018 the Company spent less on non-growth related projects resulting in a higher percentage of capital spending on growth related projects.

Q. Can you describe the increase in non-growth related spending in 2019 and 2020 as compared to previous years?

A. Yes. In 2019 and 2020, the table shows a considerable increase in the "Other" spending category. This increase is directly attributed to the construction of a new operating center. This project is discussed in the testimony presented by John Closson.

Q. What is the relevance of categorizing Tables 2 and 3 into Customer Expansion and non- Customer Expansion categories?

A. In times of higher customer expansion, the electric system benefits from renewal of aged equipment during the projects which are designed to increase the capacity of the system. When the number of new customer projects slows, the Company's facilities are not benefitting from this customer expansion related renewal and, as a result, it becomes much more challenging to address all of the periodic replacement that would be optimal for the distribution system. Over the next five years, the Company is forecasting that, on average, over 84% of its capital investment will be on projects that will not result in any increase in system load or revenue.

Q. Have you provided any historical capital spending information?

A. Yes. Exhibit KES-2 provides project by project capital spending by year from

2010-2020. The same exhibit also provides the project-by-project capital spending for 2021-2025.

D. SIGNIFICANT PROJECTS

Q. Do you have any projects in particular that you would like to describe that have already been completed?

A. Yes. I would like to describe the Concord Downtown Conversion project.

Q. Please describe the Concord Downtown Conversion?

A. In 2019 UES began construction on the conversion of portions of the Concord downtown area from 4.16kV to 13.8kV operation including associated substation and sub-transmission upgrades. These upgrades were required to accommodate customer load additions in the downtown area. These load additions consisted of approximately 5.6MW of additional customer load and another 1MW of load within the next 5 to 8 years. This project was placed in service and used and useful in 2020.

Q. Can you identify the projects that were included as part of the Concord Downtown Conversion?

A. The table below identifies the projects that were completed to convert a portion of the Concord downtown from 4kV to 13.8kV.

Auth No.	Project	Cost
190149	Conversion in Downtown Concord Part 1	$194,714
200124	Conversion in Downtown Concord - Part 2	$447,840
190181	Reconductor/Convert Circuit 1H6 - Thompson	$137,385

	Street, Concord	
190174	Reconductor 1H6 - Pleasant and Green Street, Concord	$161,963
190192	Reconductor/Convert Circuit 1H6 - S Spring St., Concord	$371,975
190118	Gulf Street Substation – Outside Services	$3,164,045
190198	374 Line Rebuild with 15kV Underbuild	$787,358

The project consisted of a rebuild of Gulf Street substation and conversion to 13.8kV and a conversion of the Gulf Street circuits and the reconductoring and conversion of Bridge Street circuit 1H6. The downtown conversion is expected to accommodate up to 10MVA of additional load without further substation upgrades. Depending on where load enters the area, additional work could be required to connect the load to this capacity. In addition to the 10MVA of additional capacity, Gulf Street substation was designed to accommodate the future conversion of the remaining 4.16 kV circuit, the future installation of a second 14MVA transformer and the future installation of a fourth circuit position.

Q. Did the Company evaluate alternatives to the Concord Downtown projects listed above?

A. Yes. The Company also evaluated 1) replacing Gulf Street transformer 3T2 with a 34.5kV/13.8kV transformer and transferring some load away from Gulf Street substation (a.k.a. downtown conversion), 2) creating a 13.8kV transformer grid by installing several taps off of the 34.5kV system and installing several 34.5/13.8kV pad-mounted transformers, 3) Upgrade and convert Bridge Street substation to 13.8kV, 4) add transformation to Iron Works Substation, or 5) upgrade of circuits

21W1P and 21W1A.

Q. Which alternative was chosen for this project?

A. Option 1 was selected to convert a portion of downtown Concord to 13.8kV because it was the most feasible and cost effective option to increase the capacity of the downtown Concord area within the timeframe requested.

Q. Can you describe why the other options were not selected?

A. Option 2 was not feasible due to limited space in the downtown Concord, limited timeline for completion and the unknown with the future I-93 expansion. Option 3 was not chosen due to space limitations at Bridge Street substation. The time required to locate and procure adequate land space for a new substation was outside the timeline for the in-service date. Option 4 was not selected because of loading constraints on Iron Works Road Substation. The total load on both transformers (old and new) would be greater than the combined rating for the two transformers. Option 5 was not selected because underground construction made the project too costly. There are no additional conduits in the underground for new circuits, which means excavation of several streets to install new conduit and loading issues on existing underground circuits.

Q. Are there challenges associated with the evaluation of projects?

A. Yes. The Concord downtown area is in close proximity to I-93. The State of NH is currently in the process of evaluating options for the widening of I-93. The widening project has the potential to impact UES infrastructure, including Bridge

Street and Gulf Street substations. In addition, the downtown underground was built to have a primary (21W1P) and alternate (21W1A) feed to allow one of the circuits to back the other one up completely. Due to load growth in the area this is no longer the case. Depending on the fault location, portions of the downtown underground need to be restored from overhead distribution circuits. The Capital Master Plan details the future goal of returning the downtown underground to its original purpose. Finally, available land in the downtown Concord is very limited. Combined with the unknowns of the I-93 widening and the timeframe in which upgrades are required, finding locations for new substation infrastructure will be extremely difficult.

Q. Did the Company complete an evaluation of non-wires alternatives ("NWA") for this project?

A. No. This project was evaluated per the Company's Project Evaluation Process and did not require the review of NWA because the required construction start date was one year in the future.

Q. Do you have any projects in particular that you would like to describe that will be included in upcoming step adjustments?

A. Yes. I would like to describe the 3348/3350 Line Rebuild Project, 37 Line Reconductoring Project, and the Company's proposed Grid Modernization Plan.

Q. Please begin by describing the 3348/3350 Line Rebuild Project.

A. The 3348, 3350 and a small portion of the 3359 lines are constructed across the salt marsh in Hampton, Hampton Falls and Seabrook. This line was originally constructed in the 1950's. The majority of the line is approaching 70 years old. There are condition-related concerns associated with the aging infrastructure and significant accessibility and permitting challenges exist due to the location of the lines. This can cause the line(s) to be out of service for several months at a time when structure damage occurs.

This project consists of rebuilding almost 5 miles of line in its present location with single pole, armless construction. The design for this line is currently underway. Construction will take place over two years. The current budget has the project beginning in 2021 and finishing in 2022 at a total price of $10.4 million.

Q. Can you describe the reliability performance of these lines?

A. In the past ten years, the line has been out of service more than a month at a time on five different occasions. Repairs to the line are costly and time consuming. Permitting is required to complete any work on the line due to the location in the marsh. The line is only accessible by boat. Equipment and materials must be delivered by barge and only at high tide. This limits the amount of work that can be completed at any one time. Every time the line experiences damage it affects more than 3,000 customers in the towns of Hampton, Hampton Beach, Hampton Falls and Seabrook.

Q. Did the Company evaluate different alternatives to a complete line rebuild for this project?

A. Yes. The Company evaluated options of rebuilding the lines in place, constructing new lines along a different right-of-way route, constructing a new line along the railroad right-of-way, constructing a new line in the Interstate 95 right-of-way, the option of constructing this line along Route 1 with distribution circuits attached to the same poles, and constructing a new system supply substation in Seabrook. Rebuilding the lines in place was the most cost effective option.

Q. Is this the same project that was presented in docket DE 20-002 UES Least Cost Integrated Resource Planning ("LCIRP")?

A. Yes. The Company answered many discovery requests about this project including the different options that were evaluated. During the docket, Staff requested the Company to have an outside firm evaluate if an incremental repair option would be more beneficial than a line rebuild option.

Q. Was this evaluation completed?

A. Yes. The Company hired TRC to evaluate and compare a line rebuild option versus an incremental line repair option. The Company shared the scope of work and the final report with Commission Staff in the UES LCIRP docket. Based upon the analysis, TRC recommends the complete rebuild of the lines. Considering previous data provided and the load forecast for these lines, the Company anticipates that completely rebuilding the line will cost less money over the lifetime of the lines than incrementally repairing the lines, as well as provide reliability benefits (including but not limited to splice and conductor life, increased reliability in wind events, and lightning protection) and other benefits such as avian impacts and future development options.

Q. Has the Company experienced any other outage events since the evaluation?

A. Yes. On February 17, 2021, the 3350 line experienced an outage affecting over 3,000 customers. The outage was caused by a split pole top which resulted in the bolt that holds the static wire being pulled out and the static wire falling into the phase conductors. The lines are now out of service again as the Company obtains the necessary permits to work on the marsh to make the repair. This latest outage further confirms the need for the Company to completely rebuild the 3348, 3350, and 3359 (partial) lines.

Q. Please describe the 37 Line Reconductoring Project?

A. The UES-Capital 37 line loading constraint is a planned contingency loading concern. This loading constraint exists when the 37 line is utilized to restore all load for the loss of 4X1 at Penacook with all hydroelectric generators and the trash burning generator considered out of service. Per UES's planning criteria, this is how the area would be studied during summer peak loads. The 37 line loading constraint is due to general load growth and approximately 750kVA additional load from a new commercial development that will be supplied via the 37 line. The line is forecast to be approximately 117% of the normal rating.

The 3.5MW deficiency is based on 2022 forecasted peak loads. In 2021, the 37 line, while supplying 4X1 with the largest generator and all hydroelectric generators out of service (these are typically not operating during summer peak times), is expected to be loaded to 18.1MW or 3MW above normal. It is UES's intent that any project that is implemented reduces line loading below its normal rating to provide sufficient capacity for future load growth and extend through the end of the ten-year study timeframe. Since the completion of the latest planning study and the decision to reconductor the 37 line, additional information was received regarding the proposed commercial development mentioned above. Phase 1 of this development is currently under construction and is now anticipated to be between 1.5MW and 2MW of load. This project consists of reconductoring the 37 Line from Penacook substation to the MacCoy Street tap.

Q. Is this the same project that was presented in docket DE 20-002 UES LCIRP?

A. Yes. The Company answered many discovery requests about this project including the different options that were evaluated.

Q. Did the Company consider NWAs for this project?

A. Yes. When the 37 line loading constraint was identified, the needed in-service date of the project(s) to address the constraint was one year in the future. Based on UES's Project Evaluation Guideline, this project did not require a review of NWAs. The primary reason projects need to be three to five years in the future to require NWA review is to provide the Company adequate time to explore and implement NWA projects, including energy efficiency and load curtailment. However, in an attempt to test the possibility of an NWA, the Company elected to accept limited risk and defer the implementation of a traditional alternative and issue an NWA Request for Information ("RFI"). This was done to allow the Company to learn from the process of issuing an RFI for NWAs to external vendors, including types of technologies that would be proposed and costs of said technologies. The NWA RFI was open to all solutions, including energy efficiency and demand response. In the event the RFI resulted in an economically feasible project, UES would have issued a more detailed Request for Proposal.

Q. What was the result of the RFI for the 37 Line?

A. The Company issued an RFI to 19 different companies. Four of those companies presented proposals for consideration. Each of the proposals consisted of a Photovoltaic ("PV") or PV plus storage solution. Based on the analysis of all project alternatives, including the NWA proposals, the conclusion was that the best project option to address the identified 37 line constraint is to reconductor the 37 line from Penacook to the MacCoy Street tap.

Q. How has this process informed the Company's approach to future NWA analysis?

A. The Company determined that the traditional project cost to trigger an NWA review remain at $250,000 without overheads. However, it is also determined that the review of NWA projects be triggered when equipment is expected to exceed 80% of its normal rating during the first five years of the study period and exceed 90% of its normal rating in year five of the study period under base case/normal configuration conditions. Under planned contingency configurations it is recommended that NWA project reviews be triggered when equipment is expected to exceed 90% of its normal rating during the first five years of the study period and exceed 100% or its normal rating in year five of the study period. The intent of these loading thresholds is to review and possibly implement NWA projects to defer planning violations opposed to using NWA projects to resolve planning violations.

Q. Are there any other significant projects being presented in the testimony of other witnesses in this rate case?

A. Yes. The Company is proposing an EV Make Ready Program and associated time-of-use ("TOU") rate offering that is discussed in the testimony of Cindy Carroll and Carleton Simpson. Mark Lambert has submitted testimony on the Company's Customer Information System ("CIS") project. John Closson has submitted testimony on the Company's new operations building located in Exeter, NH.

IV. GRID MODERNIZATION PLAN

Q. Is the Company proposing a Grid Modernization Plan as part of this rate case?

A. Yes. The Company is proposing a group of foundational grid modernization projects to be included within its capital spending plan. The proposed Grid Modernization Plan (the "Plan") covers a span of ten years and has been provided as Exhibit KES-3.

Q. Can you summarize the proposal?

A. Yes. The table below identifies the proposed projects and spending estimates.

	Project Costs (000's)										
Projects	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Field Area Network	$ 90	$ 56	$ 127	$ 626	$ 325	$ 463	$ 780	$ 811	$ 640	$ 704	$ 4,622
ADMS and DERMS	$ 668	$ 468	$ 378	$ 298	$ 170	$ -	$ -	$ -	$ -	$ -	$ 1,981
Volt/VAR Optimization	$ -	$ 383	$ 2,000	$ 2,929	$ 2,731	$ 2,862	$ 2,880	$ 3,416	$ 3,488	$ 4,292	$ 24,981
SCADA	$ -	$ 1,530	$ 1,740	$ 760	$ 790	$ 250	$ 340	$ 420	$ 550	$ 760	$ 7,140
Mobile Damage Assessment	$ 449	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 449
AMI/OMS Integration	$ 107	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 107
Data Sharing Platform	$ 449	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 449
Total	$1,763	$2,437	$4,245	$4,612	$4,016	$3,575	$4,000	$4,647	$4,678	$5,756	$ 39,729

Q. Why is the Company filing a Grid Modernization Plan separate from its LCIRP?

A. The least cost planning approach to grid modernization will effectively identify "geographic" grid investments. "Geographic" grid investments target specific constraints on the distribution system to alleviate capacity concerns in a certain area by introducing more DERs in a specific geographic area. The LCIRP approach is not focused on the "foundational" grid modernization projects designed to implement base functionality required to advance the grid. This is an effort by the Company to begin making progress on "foundational" grid modernization projects while the LCIRP docket continues. The Company will propose "geographical" grid modernization projects when they make sense in subsequent LCIRP filings.

In addition, the Company's next LCIRP filing is projected to be filed in 2023. The Company is proposing to begin implementation of "foundational" grid modernization investments prior to the filing of the next LCIRP. With that said, the Company will include this Plan and any updates to the Plan based upon stakeholder input and changing requirements within its next LCIRP filing.

Q. Can you describe what you mean by "foundational" grid modernization projects?

A. Yes. "Foundational" Grid Modernization projects are those projects that are required to achieve the desired outcomes and core functionality. Foundational projects are typically focused on communication or technology required to implement programs or services. AMI is a foundational investment used to facilitate time-varying rates (including TOU) and data sharing, as well as planning and operational needs. Foundational investments include grid monitoring and control center software and communications systems designed to assist grid operators make better decisions in response to reconfiguring the grid in response to service outages, variation in DER output and optimization of system performance.

I will provide an example of a "foundational" Grid Modernization investment. One key foundational area of Grid Modernization is the ability to have real-time monitoring and control of the distribution system, allowing the distribution system to be operated in optimized manner. An Advanced Distribution Management System ("ADMS") and SCADA are the means to enable real-time monitoring and control. Neither of these projects are successful without a Field Area Network ("FAN") to enable communications between the central office and the field edge devices. These types of projects are not identified through least cost planning. They are foundational projects used to implement the capabilities and functionalities of a modern grid. These systems need to be put in place before the functionality can be extended to the outer edges of the system. For this reason, there is justification to consider these foundational types of investments outside of the least cost planning approach.

Q. How does this differ from the proposal in the Grid Modernization docket?

A. This does not change the efforts or the approach to planning that have been proposed in the Grid Modernization docket. The Company has been engaged with the Commission Staff, Office of the Consumer Advocate, other utilities, and stakeholders in a Grid Modernization process which is heavily focused around Grid Modernization through a least cost planning lens. The Company supports this approach for "geographic" based grid modernization investments. However, this approach does not address how "foundational" projects are implemented. Least cost planning will identify that a demand response program in a certain area of the system may be the most appropriate plan for shifting load enough to defer a capital investment, but without a foundational Distributed Energy Resource Management System ("DERMS") in place, a demand response program can be extremely difficult to implement with the level of control necessary to rely on it from a distribution planning and operations perspective.

Q. How does the Company propose to evaluate "foundational" grid modernization investments?

A. One of the most effective ways to evaluate "foundational" grid modernization investments is on a benefit-cost basis. However, most foundational grid modernization projects do not result directly in benefits to the customer. In this case, the cost of the "foundational" investment is included in the benefit-cost analysis of the project which delivers the benefits. For instance, a FAN in and of itself does not lead to quantifiable benefits. However, when a FAN is combined with a Volt/Var Optimization ("VVO") project, the benefits can be quantified and compared to the cost.

Q. Are you saying that a portfolio approach to a benefit-cost analysis is the best approach?

A. Yes. In the FAN and VVO example, if the FAN is evaluated as a stand-alone project, it would not pass a benefit-cost analysis. However, the VVO project would generally provide enough saving to pass a benefit-cost analysis, but the project will not be effective without the FAN. A portfolio approach to the group of the projects proposed in the Company's plan will provide the best indication if the Plan as presented provides benefits that exceed the estimated costs.

Q. Can all benefits be quantified in the benefit-cost analysis?

A. No. There are quantitative and qualitative benefits to all of the projects. The VVO project can provide measurable and quantifiable benefits related to reduced energy consumption and reduction in demand. It can also reduce greenhouse gas emissions, but the monetary benefit to reduced greenhouse gas emissions is not as straightforward to calculate.

Q. Now that you have explained the difference between "foundational" versus "geographical" investments, can you provide an overview of your proposed Grid Modernization Plan?

A. Yes. A reliable, affordable and fully modernized electric grid is an essential pillar of modern society. It will power the basic necessities of life while supporting new technologies, services and interactivity. It will operate more efficiently, optimize grid-connected resources and enable dramatic expansion of clean energy to protect and preserve the environment. It will foster innovation and enable new markets by optimizing benefits to customers, service providers and other stakeholders. At its fullest potential, it will harness technology innovation to connect customers, markets, solution providers and new technologies to achieve the full potential of an advanced 21st Century energy system.

Over the years this vision has been variously referred to as Grid Modernization, the Modern Grid, and the Smart Grid. But what is a Modernized Grid exactly? What does a Smart Grid look like? Is it the poles, wires and electrical infrastructure of the utility? Is it an intelligent, highly digitized electricity network that forms the basis for a "smart" power delivery system? Does it refer to the utility system, or the broader integration of customers, markets, solution providers, and others? If you ask ten different people, you will get ten different answers.

To achieve the promise of a fully modernized grid, UES views the electric grid and the devices connected to it as a communicating, intelligent grid-connected ecosystem of people, devices, information and services. The grid is only a part of this larger energy ecosystem, but it is the foundation upon which everything is built. The role of utility in this context is to enable seamless grid access, link participants, optimize resources and foster technology innovation. The modern grid isn't just an electrical network, it's a community of grid-connected and grid-enabled customers and third parties.

Q. In the past the Company has focused on the grid as an enabling platform. Has this changed in the Advancing the Grid vision?

A. Not at all. The Company's Advancing the Grid vision is focused on developing an enabling platform for customers and users of all types. The vision encompasses much more than a "poles and wires" delivery system for electricity. It will enable electrical, informational and financial transactions among customers, grid operators, service providers, markets, and other stakeholders. In doing so, it will improve load factor, lower system losses, optimize asset utilization and avoid unnecessary investments driven by "peaky" load and poor utilization. Planners and engineers will have the information to build what is needed, when it is needed, while more effectively managing capacity and resources on a day-to-day basis. Reliability will be improved through advanced outage management, distribution management and automation systems, geographical information systems and other technologies.

Achieving this vision requires a paradigm shift in what has traditionally been viewed as grid infrastructure, as well as the types of investments needed to achieve advanced functionality. Traditional utility investments focused primarily on upgrading and maintaining "electrical" infrastructure to ensure safety and reliability, increase capacity, and expand service to new customers. Customers were viewed as consumers of electricity, and the grid was designed to distribute power from large centralized generating plants to end-use consumers. Assets and investments have traditionally consisted of poles, wires, substations, and electrical equipment.

To achieve the promise of the advanced grid, investments in Information Technology ("IT") and Operational Technology ("OT") are needed to create an open, flexible platform integrating customers, competitive markets and service providers. Collectively known as "intelligence" infrastructure, these investments will include communication networks, sensors and control devices, and advanced information and management systems. Under this vision the Eco-Grid is not simply a newer, upgraded version of the legacy electric system, nor is it a specific technology or suite of technologies layered onto the existing utility systems. The Eco-Grid is instead the foundation of a larger ecosystem of customers, competitive markets and service providers who are interacting with the utility electric grid and the utility's information systems. Information and the exchange of information will be the lifeblood of this grid-connected ecosystem.

Q. Can you explain the foundational objectives developed to support the vision?

A. Yes. UES has identified a series of eight objectives that together ensure support of a modern energy ecosystem. Our objectives were crafted with guidance from the United States Department of Energy, Massachusetts Department of Public Utilities and New Hampshire Public Utilities Commission and are used to identify the investments and technologies that best serve this new era.

Objective 1: Environmentally Friendly – We must firmly support the region's goals in reducing emissions in the battle against climate change.

Objective 2: Safety and Reliability – We must continuously improve safety, reliability and resilience while reducing the effects of outages.

Objective 3: Customer Service – We must improve and embrace customer empowerment, engagement, and education. We must give the customer the tools they need to understand and control both their own energy usage and energy matters in the region.

Objective 4: Security – We must ensure the cyber and physical security of the grid remains strong.

Objective 5: Flexibility – We must ensure the grid remains flexible enough to accommodate and integrate all types of new energy sources.

Objective 6: Affordability – Energy for life must remain affordable for all.

Objective 7: Demand and Asset Optimization – The grid must be designed to get the most out of the tools and resources interconnected in order to best serve the region.

Objective 8: Technology Innovation – The grid must enable the easy adoption of new technologies as they are developed to further support customer choice and system operations.

Q. How has the Company used these objectives to develop a roadmap to the future?

A. The roadmap to the future is a journey that must be planned carefully and executed in a precise manner. It is not a sprint to implement technology just to have that technology become obsolete in two years. Some technology will serve as a foundation to other technologies. Implementing the building blocks of the advanced grid in a well thought out manner creates the enabling platform that is the basis for the Company's vision.

The Company has identified six categories of technologies required to develop the grid as an enabling platform.

1. Grid Intelligence
2. Advanced Metering
3. Distributed Energy Resources
4. Advanced System Planning and Forecasting
5. Enhanced Customer Services
6. Innovative Rate Design

Figure 1: Advancing the Grid Categories

Category 1 - Grid Intelligence: The modern electric system is changing at a rapid pace with the integration of distributed, variable and renewable resources combined and the focus on electrification of the transportation and heating sectors. New and different users are connecting to the system every day. The ever increasing levels of these resources will have a significant impact on the safe, reliable and cost effective operation of the distribution system. Increased visibility and control deep into the distribution system is quickly becoming a necessity. System optimization and efficient use of the grid resources is increasingly more important in providing a safe, reliable, sustainable and cost effective electric system. Grid Intelligence technologies rely upon a safe and reliable advanced communications system to provide communications for the monitoring and control of field devices. The Company's Grid Intelligence vision consists of centralized software systems and the installation of field devices for ADMS, DERMS, Outage

Management System ("OMS"), SCADA, VVO, and further integration of the AMI and OMS systems.

Category 2 – Advanced Metering - The modern electric system is also driven by data and information. Customers need data to inform their usage decisions. They need flexible pricing options that allow them to take advantage of their investments. Customers need to know how much electricity they are using and when that electricity is being used. Customers are willing to reduce their peak hour usage as long as they have the knowledge and tools to achieve the benefits. Timely and user-friendly data starts with a metering system that can accurately and automatically gather granular usage data, store the data in a meter data management system where it can be pushed to customers in a timely manner. Advanced Metering Functionality ("AMF") refers to the capabilities provided by the metering system. AMF provides the platform for the company to measure and provide detailed and granular interval metering data of each individual customer. In some cases AMF provides data in real-time or near real-time and in some case the AMF provides data on a daily or monthly basis. AMF data provides the information necessary for demand management programs, time of use or time varying rates, and other customized programs focused on controlling or reducing energy consumption.

Category 3 – Distributed Energy Resources: The Advanced Grid has the ability to plan for, monitor and control a diverse set of distributed assets on the system all designed to support the safe and reliable operation of the electric system.

Advanced monitoring and control technology evaluates the system in real time and issues control commands to optimize the system. An environmentally friendly grid is one that is optimized for interconnection and use of renewable resources while optimizing the system demand at all times of the year. The Advanced Grid needs to be flexible enough to integrate increased amounts of renewable energy and use these resources to optimize the system and minimize GHG emissions. The growing penetration of variable loads and intermittent renewable resources creates a challenge for the electric system if the grid is not prepared to accept these resources. The Company's vision of the advanced grid is an enabling platform with the ability to interconnect a large quantity of renewable resources and other Distributed Energy Resources ("DERs").

Category 4 – Advanced Planning and Forecasting: The growing penetration of variable loads and intermittent renewable resources creates a challenge for the electric system if the grid is not prepared to accept these resources. The Company's vision of the advanced grid is an enabling platform with the ability to interconnect a large quantity of renewable resources and other DERs. Advanced system planning forms the foundation for an enabling platform willing and ready to accept DERs and other electrification technologies. Advanced system planning begins with an accurate system model. Geographic Information Systems that are maintained on a timely basis form the network model used in Advanced System Planning. A complete and detailed network connectivity model is essential and is used across multiple platforms allows for consistent results for real time operation of the electric system. Advanced system planning reduces the risk associated with DER interconnections and enables the benefits to be realized by the system and customers. Hosting capacity and locational value analysis are tools that can be used to identify the optimal locations for DER interconnections maximizing the benefits to the customers and the system. Understanding the value and benefits of DERs will allow utilities to plan for and rely-on cost effective DER solutions to defer distribution system upgrades

Category 5 – Enhanced Customer Services: Superior customer service is fundamental to Unitil's Vision, Mission and Values. In 2020, Unitil Corporation's 93% overall customer satisfaction results were the highest in our history and significantly higher than most of our peers. From a benchmarking comparison perspective, Unitil ranked 10th out of 114 measured utilities nationally, 2nd out of 23 utilities in the Eastern Region and the 1st rated utility out of our peers in the Northeast. We earned these high levels of satisfaction by recognizing our customers' increasingly diverse and complex needs. Looking forward, we will continue to invest in technologies designed to support our commitment to the customers experience and to their satisfaction in all facets of that experience. We will strengthen current service offerings, make enhancements to our customer web portal, and add self-service options that enable customers to better manage their energy usage and accounts. These planned enhancements include a mobile app, artificial intelligence and chat features, and a robust notification engine to proactively alert customers regarding payment activity, changes in usage patterns, outages, and scheduled appointments.

Category 6 – Innovative Rate Design: The Company strongly believes the overarching objective of rate redesign should be the development of pricing for grid services that adhere to the principles of fairness, transparency and economic efficiency.

Only through transparent and economically efficient pricing structures will a viable and sustainable long term model be developed that provides sufficient revenue to support the significant investments needed to modernize the grid, while encouraging appropriate behaviors and assuring fairness and equity among customers. We continue to review how rate design must evolve to enable customers to more effectively manage their energy needs. The testimony of Cindy Carroll, Carleton Simpson, and Carol Valianti and will describe the Company's proposed EV and TOU proposal.

Q. How does the Company's Plan ensure that the included functionalities support the Plan objectives?

A. The Company's Plan maps projects and functionalities within each identified category back to the foundational objectives developed to support the Advancing the Grid vision.

Q. Does the Company detail all of the projects in its Plan?

A. Yes. Section 6 of the Plan details each proposed project, provides a project description, describes the quantitative and qualitative benefits to our customers and the grid, provides a project timeline and cost and additional description of the project and technology to be deployed.

Q. Does the plan provide net benefits to customers?

A. Yes. The benefit cost analysis uses a net-present value approach to benefits, capital cost and incremental O&M costs. The 15 and 20 year analysis results in a benefit cost ratio greater than one which is an indication of net benefits to customers.

Q. What is the Company's proposal for measuring progress towards its Plan?

A. The Company has proposed a set of metrics that will be used to quantify the Company's progress. These proposed metrics will be broken down into 1) infrastructure metrics which tracks the implementation of grid modernization technologies and 2) performance metrics that measure progress towards the objectives of grid modernization. These metrics are designed to measure quantitative benefits associated with grid modernization benefits. These metrics will be filed on an annual basis with the Plan update.

Q. How does the Company propose to report on its progress towards grid modernization?

A. The Company proposes to continue to follow the filing requirements for the LCIRP plan which is proposed to be filed every three years. The Company will continue to work with the Commission and the stakeholders to finalize the requirements of the LCIRP filing. The Company is also proposing to file additional information on an annual basis.

Q. Please identify the additional information the Company proposes to file and is the information consistent with the information that would be filed as part of the LCIRP.

A. The Company proposes to file annual planning studies, load forecasts, circuit and substation level forecasts, identification of constraints and alternative evaluated, NWA analysis for projects over estimated to be over $250,000, a summary of stakeholder input, DG interconnections by circuit and type of prime mover, discussion of progress on grid modernization projects including reasons for deviation from the prior year's plan and metrics. This information is consistent with the information required as part of the LCIRP filing. This additional information would be filed annually on the years in between the LCIRP filings.

Q. Does the Company propose a stakeholder process as part of its Plan?

A. Yes. The Company vision of Advancing the Grid is to develop an enabling platform that serves all customers and users of the system. Stakeholder engagement is designed to improve the overall transparency of the distribution planning process. Stakeholder engagement is an important aspect to determining the functionality desired in the advanced grid. The Plan is a living document and will be flexible enough to adjust to the changing requirements of the system.

Q. What does your proposed stakeholder process look like?

A. The Company will follow the stakeholder process that is required in conjunction with the LCIRP filing. However, if a stakeholder process is not detailed, the Company proposes to use the following process:

Meeting 1: Pre-Planning Meeting – The goal of this meeting is for the stakeholder to provide some initial feedback to the Company prior to plan development, review of previous plan and any changes to assumptions.

Meeting 2: Project Identification and Consideration – The Company presents preliminary findings as a result of the planning process. Stakeholders have the opportunity to provide input to the proposed alternatives and project priorities.

Meeting 3: Project Plan – The Company presents the proposed Plan and seeks any final input.

Ultimately, the Company is responsible for the safe and reliable operation of the electric distribution system at a reasonable cost. Any alternatives considered should have an equivalent capacity, reliability, availability and life span of the competing options. The Company is confident that this approach will increase the transparency of the planning process to the stakeholder group.

Q. Is the Company proposing special rate treatment for specifically for these Grid Modernization investments?

A. The Company proposes to include these Grid Modernization investments through step adjustments as part of a multi-year rate plan as described in the testimony of Messrs. Christopher Goulding and Daniel Nawazelski.

Q. Does this conclude your testimony?

A. Yes, it does.

CONSTRUCTION BUDGET 2010 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	BLANKETS ELECTRIC						
BAB10	T&D Improvements	200	831.4	602.2	802.6	Active	M
BAB11	Transformer PCB Removal	1000	0		0	Active	M
BAC10	T&D Improvements, Carryover	9000	23	794.4	-2.9	Completed 1/2010	M
BAO08	T&D Improvements	8000	0	605.4	0	Closed 11/2010	M
BBB10	New Customer Additions	201	186.2	176	245.5	Active	C
BBB11	Overhead Services	1001	0		0	Active	C
BBC10	New Customer Additions, Carryover	9001	23.1	184.1	5.1	Completed 1/2010	C
BBO08	New Customer Additions	8001	0	265.5	-23.6	Closed 2/2010	C
BCB10	Outdoor Lighting	202	83.3	82.7	110.7	Active	M
BCB11	Outdoor Lighting	1002	0		0	Active	M
BCC10	Outdoor Lighting, Carryover	9002	5.8	72.8	1.9	Completed 1/2010	M
BCO08	Outdoor Lighting	8002	0	101.2	0	Completed 2/2010	M
BDB10	Emergency & Storm Restoration	203	355.3	324.2	368.9	Active	M
BDB11	Emergency Restoration	1003	0		0	Active	M
BDC10	Emergency & Storm Restoration, Carryover	9003	6.9	448.9	-44.7	Completed 1/2010	M
BDO08	Emergency & Storm Restoration	8003	0	321.9	-73.8	Completed 2/2010	M
BEB10	Billable Work	204	127.1	88.6	37.6	Active	M
BEB11	MV Accident - Broken Pole	1004	0		0	Active	M
BEC10	Billable Work, Carryover	9004	3	246.8	2.2	Completed 1/2010	M
BEO08	BILLABLE	8004	0	183	-27.1	Closed 2/2010	M
BFB10	Transformers Company/Conversions	205	63.8	12.5	0	Active	I
BFB11	COMPANY TRANSFORMER	1005	0		0	Active	I
BFO09	TRANSFORMER-COMPANY	9005	0	28.4	0	Closed 1/2010	I
BGB10	Transformer Customer Requirements	206	526.1	434	426.8	Active	C
BGB11	CUSTOMER TRANSFORMER	1006	0		0	Active	C
BGC10	Transformer Customer Requirements, Carryover	9006	10.4	378.1	3.8	Closed 11/2010	C
BHB10	Meter Blanket Company Requirements	208	97.2	97.2	119.3	Active	M
BHB11	Electric Meter Purchases - Company Requirements	1008	0		0	Active	M
BHO09	METER-COMPANY	9008	0	45.3	0	Closed 4/2010	M
BIB10	Meter Blanket Customer Requirements	207	117.5	117.5	42.1	Active	C
BIB11	Electric Meter Purchases - Customer Requirements	1007	0		0	Active	C
BIO09	METER-CUSTOMER	9007	0	148.2	21.6	Closed 1/2010	C
		Sub-Totals:	2,460.00	5,759.10	2,016.00		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS ELECTRIC						
ECE01	Two Way Radio Replacements	224	3	3	1.3	Active	O
ECE02	AMI Equipment, Unanticipated Replacements	212	52.8	52.8	16.9	Active	O
ECE06	SCADA Master Disk Backup System	235	7.8	3	2	Closed 9/2010	O
ECE09	Purchase SCADA Terminal	216	2	2	1.5	Closed 10/2010	O
ECE11	AMI Communication Trouble Call Response	256	9.9	9.9	0	Active	O
ECE12	SCADA Data Exchange with PSNH		17.4			Cancelled 10/2010	O
EEC01	Replace SCADA System (Phase 2)	250	16.1	16.1	17.8	Closed 11/2010	O
EEC02	AMI Installation Augmentation	8010	14.3	85	1.5	Active	O
		Sub-Totals:	123.2	171.7	41		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS GENERAL						
ECC01	Outage Management System (OMS)	9059	180.2	667.5	99.2	Active	O
ECN01	Centralized Radio Electric Dispatch	228	0	7	8.4	Closed 9/2010	O
ECN02	ODI Enhancements/updates	234	0	1.1	0.6	Closed 11/2010	O
ECN03	CIS 2010 Projects	238	0	37.3	33.5	Active	O
ECN05	Unitil Website	248	0	23.1	20.7	Active	O
ECO01	Two Way Radio Replacements	9022	0	4	0	Closed 1/2010	O
ECO02	AMI Replacements	9048	0	26.3	0	Closed 10/2010	O
ECO03	SCADA MASTER PH 2	5057	0	202	0	Closed 6/2010	O
		Sub-Totals:	180.2	968.3	162.4		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	DISTRIBUTION ELECTRIC						
DAB00	Overhead Line Extensions		28.8		-5.2	Active	C

Electric Category	2010
Growth	
Customer Additions (C)	807,300
Subtotal Growth	807,300
Non-Growth	
Reliability (R)	235,900
Maintenance Replacement (M)	2,445,000
Mandated (H)	74,700
System Improvement (I)	1,138,900
Other (O)	817,800
Subtotal Non-Growth	4,712,300
Total	5,519,600
	5,519,600
	0

Budget Category	
Annual Requirements Blankets	**2010**
T&D Improvements	799,700
New Customer Additions	227,000
Outdoor Lighting	112,600
Emergency & Storm Restoration	250,400
Billable work	12,700
Transformers	430,600
Meters	183,000
Sub-Totals:	**2,016,000**
Distribution	
Overhead Line Extensions over $20,000	(5,200)
Underground Line Extensions over $20,000	67,600
Street Light Projects	-
Telephone Company Requests	69,600
Highway Projects	50,500
Distribution Pole Replacements	335,600
Specific Projects: Distribution	2,473,400
Sub-Totals:	**2,991,500**
Substation	
Specific Projects: Substation	232,300
Sub-Totals:	**232,300**
Communications	**203,400**
Tools, Shop, Garage	**55,600**
Laboratory	**1,900**
Office	**800**
Structures	**18,100**
Distribution Totals:	**5,519,600.0**

CONSTRUCTION BUDGET 2010 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DAB01	3 PH, O/H Line Ext., 4 Northeast Ave, Bow	239	0	6.5	6	Closed 10/2010	
DAB02	Pole Relocations	247	0		-11.3	Completed 12/2010	
DAB03	Relocation of Poles, 45-49 S Main St, Concord	252	0		0.1	Active	
DAB99	Water St OH Line Ext-Epsom	9060	0	5	0	Closed 1/2010	
DAC00	Overhead Line Extensions - Carryover		12.5			Completed 6/2010	C
DBB00	Underground Line Extensions		62.2		27.5	Active	C
DBB01	URD Line ext-147 Loudon Rd, Concord	237	0	6.9	4.6	Closed 10/2010	
DBB02	URD Line Ext, Dunbarton Rd, Concord, St Pauls School	245	0	37.5	6	Completed 10/2010	
DBB03	Three Phase, urd line ext, 30 Pembroke Rd, Concord	254	0		-0.7	Active	
DBB04	Overhead Single Phase Guaranteed Line Extension	257	0	55.8	17.7	Active	
DBC00	Underground Line Extensions, Carryover		18.2		40.1	Completed 10/2010	C
DBC02	URG Ext-Parmenter Pl, Conc	9053	0	18.6	22.4	Completed 10/2010	
DBC03	Primary UDG Line Ext-Airport Rd Concord-NHANG	9056	0	7.9	0.9	Closed 4/2010	
DBC04	7X1 conversion & 3 ph URD Line Ext	9057	0	63.4	12.7	Closed 10/2010	
DBC05	Tower Cir URD Line Ext	9058	0	7	2.4	Closed 4/2010	
DBC06	3 Phase Pri URD Line Ext-45 Constitution Ave	9062	0	11.3	1.8	Closed 4/2010	
DBC08	URD Line Ext-Ph 3 Vineyards	8068	0	15.1	0	Closed 4/2010	
DCB00	Street Light Projects		12			Active	M
DCC00	Street Light Projects - Carryover		0.7			Completed 3/2010	M
DDB00	Telephone Company Requests		30		24.2	Active	H
DDB01	Penacook St. Conc-Fairpoint Req Add Height	241	0	30	24.2	Closed 11/2010	
DDC00	Telephone Company Requests, Carryover		0			Completed 3/2010	H
DEB00	Highway Projects		371.7		45.4	Active	H
DEB01	Manchester St., Road Relocation		0			Active	
DEB02	N State St. Conc-Relo (4) for Rd Constr	236	0	59.8	45.4	Closed 10/2010	
Dec-00	Highway Projects, Carryover		0			Completed 3/2010	H
DEO01	Relocate (7) poles and primary UG feed along roadway	9039	0	123	5.1	Closed 9/2010	H
DPB01	Condemned Poles	217	264.2	264.2	335.6	Active	M
DPB02	Purchase Voltage Regulators	242	44.7	44.7	11.3	Active	I
DPB04	Circuit 1H6 reconductoring along the 374 Line R.O.W.	225	106.9	246.6	233.6	Active	I
DPB05	Circuit 4W3, Replace sectionalizers on Abbott Road	215	1.2	15.5	7.5	Closed 9/2010	M
DPB06	Circuit 22W3, Upgrade Reclosers coil at Birchdale Rd	233	8.6	8.6	3.8	Completed 10/2010	M
DPB09	Circuit 4X1, Add 2 phases and Reconductor Carter Hill Road	231	148.3	207.2	207.4	Active	I
DPB10	Purchase Easement - 396 Line	226	597.3	597.3	305.7	Active	O
DPB12	DER - Crutchfield Solar Hot Water System		101.9			Active	C
DPC01	New 34.5 kV Line Garvins to Bow Junction	8066	1,435.30	2,269.00	774.8	Active	I
DPC02	38 Line Recloser at Horse Shoe Pond Tap	9042	14	65	41.9	Completed 10/2010	M
DPC03	38 Line Load Break and Remote Control Switch	9041	14	80	5.1	Active	M
DPC04	Purchase VacPac Switch	227	17.3	17.3	0	Cancelled 8/2010	M
DPN01	Wind Storm February 2010	255	0	698	681.6	Closed 9/2010	M
DPN03	Dec. Ice Storm	9064	0	540.2	0	Closed 2/2010	M
DPN04	One pole primary line extension	9066	0	23.6	23.6	Closed 10/2010	C
DPN10	Replace failed URD cable and terminators	253	0	74.6	74.6	Closed 10/2010	M
DPO01	Purchase Voltage Regulators	9045	0	108.7	12.6	Closed 10/2010	I
DPO02	Install (3) Voltage Regulators on Pole 65 Dover Rd	9043	0	86.7	0.9	Closed 5/2010	I
DPO03	Upgrade Stepdown transformer from 333kVA to 500kVA	9032	0	1.7	0	Closed 4/2010	I
DPO04	Cir 7W3 Add line ext to replace tie with Cir 22W3	9033	0	108	0.2	Closed 11/2010	M
DPO05	DW Highway, Boscawen Replace Failing Direct Buried Cable	9063	0	41.9	0	Closed 4/2010	M
DPO06	Puchase Volt Regulators 100 am	8050	0	15.3	0	Closed 10/2010	I

Electric Category	2010

Budget Category

CONSTRUCTION BUDGET 2010 UES Capital							
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED							
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DPO07	NEW SYSTEM SUPPLY,-Dist Easement	5073	0	726	-101.7	Closed 1/2010	I
DRB00	Reliability Projects		0		211.4	Active	R
DRB06	Circuit 13W2 Rebuild High St p. 83 to 110 on other side of the Street	211	208.5	208.5	211.4	Closed 9/2010	
DRC00	Reliabilty Projects, Carryover		0			Completed 6/2010	
DRO01	Cir 13W2 - Upgr High St Recl	9054	0	55	15.1	Closed 10/2010	R
DRO02	Install three-phase recl	9055	0	69.5	9	Active	R
DRO03	Cir 22W3 Birchdale Rd, Bow Install Spacer Cable	9061	0	104.8	0.4	Closed 4/2010	R
		Sub-Totals:	3,498.30	7,125.60	2991.5		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE ELECTRIC						
EAE02	Purchase and Replace Hot Line Tools	218	2.5	2.5	1.7	Active	O
EAE03	Purchase and Replace Rubber Goods	219	3.3	3.3	5.2	Active	O
EAE04	Normal add & replace - tools & equipment EM&C	213	10	10	7	Active	O
EAE09	Man hole cover lifting system	229	2.1	2.1	2.2	Closed 10/2010	O
EAE13	Purchase/replace URD Grounding Equipment		3			Active	O
EAE19	Purchase Fire Retardant Safety Equipment		11			Active	O
EAE20	Purchase five (5) sets of Overhead Grounding Kits	222	30	30	30.9	Closed 9/2010	O
EAE21	Tools, Shop & Garage - Normal Additions and Replacements	220	10	10	8.7	Active	O
		Sub-Totals:	71.9	57.9	55.7		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE GENERAL						
EAO01	Tools, Shop, Garage Normal Additions and Replacements	9016	0	10	0	Closed 1/2010	O
EAO02	Purchase Hot Line Tools	9018	0	2	0	Closed 1/2010	O
EAO03	Purchase rubber goods	9020	0	3	0	Closed 1/2010	O
EAO04	Purcase 1 Symbol Handheld	9013	0	4	0	Closed 1/2010	O
EAO06	Purchase 7 portable grounding mats	9023	0	3.2	0.1	Closed 1/2010	O
EAO08	Purchase Tools and Equipment - EM&C	9035	0	4	-0.2	Closed 10/2010	O
EAO10	Lab Equipment - Normal Additions and Replacements	9049	0	3	0	Closed 5/2010	O
		Sub-Totals:	0	29.2	-0.1		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	LABORATORY GENERAL						
EBB01	Lab Equipment - Normal Add and Replace EM&C	214	5	5	1.9	Active	O
		Sub-Totals:	5	5	1.9		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE ELECTRIC						
EDE01	Office Furniture & Equipment-Normal Additions and Replacements	221	3.5	3.5	0.8	Active	O
		Sub-Totals:	3.5	3.5	0.8		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE GENERAL						
EDO01	Office Furniture and Equipment	9010	0	3.5	0	Closed 1/2010	O
		Sub-Totals:	0	3.5	0		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	STRUCTURES GENERAL						
GPB02	Normal Improvements to Capital Facility	223	10	10	6.9	Active	O
GPB03	Install Backup A/C Unit in Data/Tel Room	232	10	10	11.2	Active	O
GPO01	Normal Improvements and Replacements Facility	9019	0	10	0	Closed 1/2010	O
GPO02	EOC Furniture	9047	0	33	0	Closed 1/2010	O
		Sub-Totals:	20	63	18.1		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	SUBSTATION ELECTRIC						
SPB02	Iron Works Road - Install Capacitor Banks	243	125.4	125.4	25.1	Active	O

Electric Category	2010		Budget Category

CONSTRUCTION BUDGET 2010 UES Capital							
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED							
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
SPB11	West Concord - Replace Strain Bus	230	220.9	220.9	54.6	Closed 11/2010	O
SPC01	Build 34.4-13.8 kV Mobile Substation	251	130.7	131.2	64.6	Active	O
SPC02	Replace Damaged Equip at Pleasant St S/S Concord	6066	34	67	0.2	Active	O
SPC03	Replace 33 Line Recloser at Bow Junction S/S	9044	87.7	130	70.3	Completed 9/2010	O
SPC04	15W2 West Portsmouth Street and 2H1 West Concord Breaker Changeouts	259	10	10	14.3	Completed 12/2010	O
SPO01	Replace station batteries at Pleasant St S/S	9051	0	8.3	3.3	Closed 9/2010	O
SPO02	Purchase New Transformer	9026	0	475	5	Closed 11/2010	O
SPO03	AMI Substation Work completed in 2006.	9065	0	28.6	-5.1	Closed 4/2010	O
SPO04	Replace 1H3 Breaker	8073	0	53.3	0	Active	O
SPO09	Build Mobile Substation	8061	0	1,793.10	0	Closed 6/2010	O
		Sub-Totals:	608.6	3,042.70	232.3		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TRANSPORTATION ELECTRIC						
1-Feb	Replace truck #45		0			Completed 4/2010	O
		Sub-Totals:	0	0			
		Grand Totals:	6,970.70	17,229.40	5,519.60		

Electric Category	2010		Budget Category

CONSTRUCTION BUDGET 2010 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	BLANKETS ELECTRIC						
BAB10	T&D Improvements	200	964.9	1,149.00	1,236.20	Active	M
BAB11	Transformer PCB Removal	1000	0		0	Active	M
BAC10	T&D Improvements, Carryover	9000	84.5	1,087.40	59.2	Completed 1/2010	M
BAO08	T&D Improvements	8000	0	672.5	-4.5	Closed 10/2010	M
BBB10	New Customer Additions	201	397.9	399.8	468.3	Active	C
BBB11	Overhead Services	1001	0		0	Active	C
BBC10	New Customer Additions, Carryover	9001	16	340.5	5	Closed 9/2010	C
BCB10	Outdoor Lighting	202	185.5	190.4	277	Active	M
BCB11	Outdoor Lighting	1002	0		0	Active	M
BCC10	Outdoor Lighting, Carryover	9002	8.6	178.6	1.7	Completed 1/2010	M
BDB10	Emergency & Storm Restoration	203	576	584.4	525.4	Active	M
BDB11	Emergency Restoration	1003	0		0	Active	M
BDC10	Emergency & Storm Restoration, Carryover	9003	17.1	367.4	21	Completed 1/2010	M
BDO08	EMERG & STORM REST.	8003	0	393.1	0	Closed 4/2010	M
BEB10	Billable Work	204	346.6	342.6	180.5	Active	M
BEB11	P 142/28 broken pole replaced	1004	0		0	Active	M
BEC10	Billable Work, Carryover	9004	15.5	237.4	-5.9	Active	M
BEO07	BILLABLE WORK	7004	0	242.3	-0.3	Closed 4/2010	M
BEO08	Billable Work	8004	0	293.5	-3.6	Closed 6/2010	M
BFB10	Transformer Company/Conversion	205	227.6	227.6	196.6	Active	I
BFB11	COMPANY TRANSFORMER	1005	0		0	Active	I
BFC10	Transformers Company/Conversion Carryover	9005	0	217.5	0	Closed 1/2010	I
BGB10	Transformers Customer Requirements	206	785.5	772.7	1,018.60	Active	C
BGB11	CUSTOMER TRANSFORMER	1006	0		0	Active	C
BGC10	Transformer Customer Requirements, Carryover	9006	16.8	806.9	4.5	Closed 2/2010	C
BHB10	Meter Blanket Company Requirements	208	88.5	88.5	48	Active	C
BHB11	Electric Meter Purchases - Company Requirements	1008	0		0	Active	M
BHC10	Meters, Company Carryover	9008	0	81.6	0	Closed 1/2010	M
BIB10	Meter Blanket Customer Requirements	207	161.2	161.2	95.7	Active	C
BIB11	Electric Meter Purchases - Customer Requirements	1007	0		0	Active	C
BIC10	Meters Customer Carryover	9007	0	143.5	0	Closed 1/2010	C
		Sub-Totals:	3,892.10	8,978.30	4,123.40		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS ELECTRIC						
ECE01	AMI Equipment, Unanticipated Replacement	214	50.3	50.3	22.5	Active	O
ECE04	SCADA Data Exchange with PSNH		16.5			Cancelled 10/2010	O
ECE08	Two Way Radio Replacements	232	5	5	4.3	Active	O
ECE09	Purchase SCADA Terminal	219	5.2	5.2	0.4	Completed 10/2010	O
EEC01	AMI Installation Augmentation	8012	18.2	406	17.2	Completed 11/2010	O
		Sub-Totals:	95.2	466.6	44.4		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS GENERAL						
ECC01	Outage Management System (OMS)	9086	273.2	1,012.00	116.8	Active	O
ECN01	Centralized Radio Electric Dispatch	235	0	7	6.9	Closed 9/2010	O
ECN02	ODI Enhancements/updates	239	0	1.6	0.9	Closed 11/2010	O
ECN04	Sungard 2010 Projects	246	0	54.3	47.4	Active	O
ECN06	Unitil Website	252	0	35.4	38.5	Active	O
ECO01	Wind Turbine	8090	0	50	25.2	Active	O
ECO02	Two Way Radio Replacements	9047	0	4	0	Closed 1/2010	O
ECO03	Purchase AMI Equipment - Unanticipated	9048	0	25	0	Closed 10/2010	O
		Sub-Totals:	273.2	1,189.20	235.7		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	DISTRIBUTION ELECTRIC						
DAB00	Overhead Line Extensions - New Projects		61.3		61.8	Active	C
DAB01	Single Phase, O/H Line Ext, Pond St. Newton	238	0	15	15.7	Closed 4/2010	
DAB02	3 ph, O/H Line Ext, Rocks Rd, SE	245	0	5.8	6	Closed 11/2010	
DAB03	O/H Line Ext Parkersville Ln, SE	253	0	8	4.2	Closed 10/2010	
DAB05	Overhead Line Ext., Pond St, Newton	275	0	12.2	36	Active	

Electric Category	2010
Growth	
Customer Additions (C)	2,120,700
Subtotal Growth	2,120,700
Non-Growth	
Reliability (R)	248,800
Maintenance Replacement (M)	4,262,400
Mandated (H)	-162,100
System Improvement (I)	976,400
Other (O)	473,500
Subtotal Non-Growth	5,799,000
Total	7,919,700
	7,919,700
	0

Budget Category	
Annual Requirements Blankets	**2010**
T&D Improvements	1,290,900
New Customer Additions	473,300
Outdoor Lighting	278,700
Emergency & Storm Restoration	546,400
Billable work	170,700
Transformers	1,219,700
Meters	143,700
Sub-Totals:	**4,123,400**
Distribution	
Overhead Line Extensions over $20,000	71,900
Underground Line Extensions over $20,000	241,800
Street Light Projects	-
Telephone Company Requests	-
Highway Projects	(162,100)
Distribution Pole Replacements	362,900
Specific Projects: Distribution	2,723,800
Sub-Totals:	**3,238,300**
Substation	
Specific Projects: Substation	191,500
Sub-Totals:	**191,500**
Communications	**280,100**
Tools, Shop, Garage	**72,000**
Laboratory	**8,200**
Office	**3,700**
Structures	**2,500**
Distribution Totals:	**7,919,700**

CONSTRUCTION BUDGET 2010 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DAC00	Overhead Line Extensions, Carryover		32.3		10.1	Active	C
DAC01	Upgrade 3 PH Service, 120 Portsmouth Ave, EX	9068	0	6.5	-1.2	Active	
DAC02	Added 2 phases, 80 State Rt 125, KI	9075	0	4.1	2.1	Active	
DAC03	3 ph service, 191 South Main St, NE	9078	0	12.2	-2.3	Active	
DAC04	OH Line Ext, 99 Ledge Rd, SE	9090	0	11.8	5.9	Active	
DAC05	Relocation of Poles	8100	0	6.8	5.7	Active	
DAC06	Upgrade 3 PH Service	8102	0	12.8	0	Closed 11/2010	
DBB00	Underground Line Extensions - New Projects		164.3		208.4	Active	C
DBB01	URD Line Ext, off Ashbrook Rd, EX	236	0	41.8	40.9	Active	
DBB02	Three Phase, URD Line Ext, Epping Rd., Exeter	242	0	52.8	57.4	Active	
DBB03	URD Line Ext., Colby Rd., Danville	243	0	31.4	33.4	Closed 10/2010	C
DBB04	URD Line Ext., Hampton Rd, Exeter	244	0	10.6	9	Closed 11/2010	
DBB06	3 ph, urd line ex, off Mill Ln, Seabrook	262	0	16.9	9.5	Active	
DBB07	1 PH, Primary URD LIne Ext., 9 Deer Run, AT	269	0	3.3	9.8	Active	
DBB08	3 PH, URD Line Ext, 31 Garden Rd, Plaistow	270	0	3.7	41.2	Active	
DBB09	Three Phase, URD Line Ext, Rocks Rd/Dows Ln, Seabrook	271	0	9.2	23.7	Active	
DBB10	Single Phase, URD Line Ext, 56 Drakeside Rd., Hampton	272	0	17.5	30.3	Active	
DBB11	Three Phase, URD Line Ext., Ocean Blvd., Hampton	273	0	5.2	-46.8	Active	
DBC00	Underground Line Extensions, Carryovers		215.6		166.9	Active	C
DBC01	3 ph, URD Line Ext, Riverwoods Dr, EX	9057	0	79.3	-8.7	Active	
DBC02	URD Line Ext, Caleb Dr, Danville	9071	0	97.1	29.5	Closed 6/2010	
DBC03	URD Line Ext, Maple Ave, AT	9073	0	31.7	34.1	Active	
DBC04	URD Line Ext, Halls Way, SE, off Farm Ln	9077	0	172.5	97.7	Closed 6/2010	
DBC05	URD line ext, 59 Portsmouth Ave, EX	9091	0	11.8	10.9	Active	
DBC06	Secondary URD Line, 201 Ocean Blvd, SE	9092	0	1.3	2.2	Active	
DBC07	URD Line Ext 83 Newton Rd, PL	8101	0	18.2	1.1	Closed 9/2010	
DCB00	Street Light Projects		36.8		0	Active	M
DCB01	Installation of Street Lights,State Rt 125/Rt 121A, Plaistow	265	0	6.4	0	Active	
DCC00	Street Light Projects, Carryover		0			Active	M
DDB00	Telephone Company Requests		0			Active	H
DDC00	Telephone Requests, Carryover		0			Active	H
DEB00	Highway Projects		49.5		0	Active	H
DEB01	NHDOT, Rt. 125, Plaistow	274	847.9	701.1	0	Active	
Dec-00	Highway Projects, Carryover		117.5		-162.1	Active	H
DEC01	relocation of urd utilities, I-95 Toll, Hampton	9087	0		-162.1	Closed 9/2010	
DPB01	Condemned Pole Replacement	222	465.5	465.5	362.9	Active	M
DPB02	Regulator Capital Improvements	233	60.6	60.6	35	Active	I
DPB03	Circuit 22X1 Install Capacitor Bank on Kingston Road	234	31	31	21	Active	M
DPB04	Circuit 6W1 Convert a Portion of South Road	229	162.6	162.6	87.7	Completed 9/2010	I
DPB06	Circuit 20H1 Load Transfer to 28X1	217	235.1	235.1	206.1	Closed 11/2010	M
DPB07	Circuit 56X1 Newton Junction Road Improvements	220	268.7	268.7	304.5	Closed 11/2010	M
DPB09	Circuit 21W1 Convert Salem Road	221	191.8	191.8	119.1	Completed 11/2010	I
DPB11	Replace One structures along the 3348 Line		52.1			Cancelled 7/2010	M
DPC01	Replace Guinea Road 47X1 Regulators	8046	31	55.4	20.6	Active	I
DPC02	3343/3354 Capacitor Banks	8065	14.6	78.4	0	Active	M
DPN02	Circuit 18X1 Load Transfer to 2X2	249	0	490	432.9	Active	I
DPN03	Feb 2010 Wind Storm (c-3533)	250	0	600	576.7	Active	M
DPN05	March 2010 Wind Storm	261	0	88.8	101.6	Active	M
DPN06	Replace the failed 51X1 recloser	268	0	25	0	Active	M
DPN07	3348 Transmission Line Repairs	247	0	356	311	Active	M
DPN08	Replace neutral - Correct Stray Voltage	260	0	110	62.7	Active	M

Electric Category	2010

Budget Category

CONSTRUCTION BUDGET 2010 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DPO01	Replace & C/O Condemned Poles, Various Locations	9023	0	350	13.8	Closed 4/2010	M
DPO02	Purchase & Installation of Voltage Regulators	9015	0	252.2	0	Closed 1/2010	I
DPO03	Circuit 3H1, Transfer Ocean Blvd to 46X1	9076	0	35	0	Closed 2/2010	I
DPO04	Replace Two Distribution Capacitor Bank Controls	9084	0	11.1	0.8	Closed 9/2010	M
DPO05	Ice Storm - December 11th 2008	9058	0	1,191.90	0	Closed 1/2010	M
DPO06	46X1 Transfer to 17W1, Kings Hwy, Hamp	8061	0	355.3	0	Closed 1/2010	I
DPO07	28X1 Tap - Install Recl & Reg	8054	0	255	0	Closed 1/2010	M
DPO08	RECL/REG CIRCUIT 56X1, KINGSTON	7021	0	246.6	14.6	Completed 6/2010	M
DPO09	Rebuild & Convert 2H3 & 15W1	8014	0	1,002.80	0	Closed 1/2010	I
DPO10	58X1 - Convert Route 108/ Newton Rd to 34.5 kV	8016	0	330.6	0	Closed 1/2010	I
DPO11	Convert Portion of High St., Stratham	8076	0	72.5	0	Cancelled 1/2010	I
DRB00	Reliability Projects		0		299.3	Active	R
DRB01	Circuit 22X1 Install a Recloser on Danville Road	254	60.3	60.3	70.7	Active	
DRB02	Circuit 18X1 Install a Recloser on Route 27	264	60.3	62.3	71.4	Active	
DRB03	Circuit 5H2 Install a Recloser on Sweet Hill Road	255	60.3	60.3	72.9	Active	
DRB05	Exeter Switching Install Automatic Transfer Scheme		280.7			Cancelled 6/2010	
DRB06	Circuit 7X2 S/S Recloser Replacement	259	86.1	100	0	Active	
DRB07	Circuit 23X1 Install a Recloser on Mill Lane	256	60.3	60.3	84.3	Active	
DRC00	Reliabilty Projects, Carryover		162.7		-62.6	Active	R
DRC01	Pollard Rd, Plaistow, Circuit 58X1	9063	162.7	220	-62.6	Cancelled 4/2010	
DRO01	Main St, Circuit 21W2, AT	9062	0	90	3.4	Closed 1/2010	R
DRO02	Meditation Ln, AT Circuit 21W1	9064	0	75	8.7	Closed 1/2010	R
		Sub-Totals:	3,971.60	9,457.10	3238.3		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE ELECTRIC						
EAE01	Tools, Shop & Garage – Normal Additions and Replacements	226	10.5	10.5	14.3	Active	O
EAE02	Purchase and Replace Rubber Goods	227	3.2	3.2	5.9	Active	O
EAE03	Purchase and Replace Hot Line Tools	228	2	2	2.5	Active	O
EAE04	Purchase underground grounding equipment	225	5	5	0	Cancelled 8/2010	O
EAE09	Replace Underground Pulling Rope and Reel	223	5	6.5	6.6	Closed 10/2010	O
EAE10	Purchase tooling and equipment for truck #8		4			Cancelled 1/2010	O
EAE12	Purchase Fire Retardent Safety Equipment		13			Cancelled 9/2010	O
EAE13	Tools and Equipment EM&C - Normal Additions and Replacements	216	10	10	8	Active	O
EAE22	Purchase Overhead Grounding Kits	224	32.5	32.5	31.9	Closed 10/2010	O
		Sub-Totals:	85.2	69.7	69.2		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE GENERAL						
EAO01	Tools, Shop & Garage -Normal Additions and Replacements	9035	0	10.4	0	Closed 1/2010	O
EAO02	Purchase and Replace Rubber Goods	9036	0	3	0	Closed 1/2010	O
EAO03	Purchase and Replace Hot Line Tools	9037	0	2	0	Closed 1/2010	O
EAO06	Purchase eight (8) truck mats, Seacoast	9032	0	2.5	0	Closed 1/2010	O
EAO07	Purchase Tools and Equipment - M&S	9049	0	4	2.8	Closed 1/2010	O
		Sub-Totals:	0	21.9	2.8		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	LABORATORY GENERAL						
EBB01	Lab Equipment EM&C - Normal Additions and Replacements	215	7	7	8.2	Active	O
EBO01	Purchase Lab Equipment	9050	0	3	0	Closed 1/2010	O
EBO04	Purchase ASE200 - Comm RTU test equipment	9041	0	3.5	0	Closed 1/2010	O
		Sub-Totals:	7	13.5	8.2		

Electric Category	2010		Budget Category

CONSTRUCTION BUDGET 2010 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE ELECTRIC						
EDE01	Office Furniture & Equipment – Normal Additions and Replacements	230	3.5	3.5	3.7	Active	O
	Sub-Totals:		3.5	3.5	3.7		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE GENERAL						
EDO01	Office Furniture and Equipment	9024	0	3.5	0	Closed 1/2010	O
EDO02	Purchase Copy Machine	9044	0	10	0	Closed 1/2010	O
	Sub-Totals:		0	13.5	0		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	STRUCTURES GENERAL						
GPB01	Normal Improvements to Kensington Facility	231	10	10	1.3	Active	O
GPO01	Normal Improvements Facility	9046	0	17.5	0	Closed 1/2010	O
GPO02	EOC Furniture	9081	0	18.3	1.2	Closed 3/2010	O
GPO03	Replace Well Seacoast Doc	9085	0	17	0	Closed 3/2010	O
	Sub-Totals:		10	62.8	2.5		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	SUBSTATION ELECTRIC						
SPB01	Kingston Sub. - System Supply Additions (Yr. 1 of 3)	240	224.5	224.5	62.5	Active	I
SPC01	Westville S/S Upgrade Circuit Voltage Regulators	9055	13.9	108.4	12.1	Active	I
SPC02	2nd Guinea Capacitor Bank	8052	40	420	45.5	Completed 11/2010	O
SPC03	Guinea Station relaying	7019	167.6	221	0	Active	O
SPC04	Install Capacitor Bank - Westville S/S	8069	6.4	39.3	0	Active	O
SPC05	Replace Circuit 11W1 Recloser	8067	19.2	50.7	0	Active	O
SPO01	Purchase New Transformer	9056	0	970	56.7	Closed 10/2010	O
SPO02	Exeter S/S-Repl 4 kv switchgear w/2 circ pos	8053	0	420	4.8	Closed 4/2010	O
SPO03	19X3 - Upgrade Volt Reg	8049	0	88.1	2.2	Closed 3/2010	I
SPO04	Install Cap Banks at E Kingston Sub	8068	0	39.3	0	Completed 1/2010	O
SPO05	Replace 19X2 Relaying	7106	0	23.9	0	Closed 3/2010	O
SPO06	REGULATION CIRCUIT 19X2	7033	0	175.6	7.7	Closed 4/2010	I
SPO07	REPL FREQ RELAY, EXETER	7023	0	13.2	0	Closed 6/2010	O
SPO08	2X2 FEEDER HAMPTON SS	6022	0	270.3	0	Closed 2/2010	I
	Sub-Totals:		471.5	3,064.30	191.5		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TRANSPORTATION ELECTRIC						
2-Feb	Replace Truck #24		0			Completed 8/2010	O
3-Feb	Replace Truck #4		0			Completed 8/2010	O
4-Feb	Replace truck #36		0			Completed 8/2010	O
	Sub-Totals:		0	0			
	Grand Totals:		8,809.40	23,340.30	7,919.70		

Electric Category	2010		Budget Category

CONSTRUCTION BUDGET 2011 Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	?? ??						
DPBC01	Condemned Pole Replacements	2211	0		0	Active	M
BABC12	Electric T&D Improvements	2100	0		0	Active	M
BBBC12	New Customer Additions	2101	0		0	Active	C
BCBC12	Outdoor Lighting	2102	0		0	Active	M
BDBC12	Emergency & Storm Restoration	2103	0		0	Active	M
BEBC12	Billable Work	2104	0		0	Active	M
		Sub-Totals:	0	0	0		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	BLANKETS ELECTRIC						
BAB11	T&D Improvements	1000	816.7	820	663.3	Active	M
BAB12	Electric T&D Improvements	2100	0		0	Active	M
BAC11	T&D Improvements, Carryover	200	21.7	808.6	-14.9	Completed 9/2011	M
BAO09	T&D	9000	0		0	Closed 2/2011	M
BBB11	New Customer Additions	1001	259	255	188.2	Active	C
BBB12	New Customer Additions	2101	0		0	Active	C
BBC11	New Customer Additions, Carryover	201	23.2	250.5	6.4	Completed 7/2011	C
BCB11	Outdoor Lighting	1002	118.3	95	70.4	Active	M
BCB12	Outdoor Lighting	2102	0		0	Active	M
BCC11	Outdoor Lighting, Carryover	202	4	113.7	0.1	Completed 5/2011	M
BDB11	Emergency & Storm Restoration	1003	413.7	472.2	507.3	Active	M
BDB12	Emergency & Storm Restoration	2103	0		0	Active	M
BDC11	Emergency & Storm Restoration, Carryover	203	7.1	324.2	-27.7	Completed 7/2011	M
BDO09	Emergency Restoration	9003	0		0	Closed 2/2011	M
BEB11	Billable Work	1004	164.7	175	-55.9	Active	M
BEB12	Billable Work	2104	0		0	Active	M
BEC11	Billable Work, Carryover	204	3.5	88.6	63.1	Active	M
BEO09	Billable Jobs	9004	0	246.8	4.6	Closed 8/2011	M
BFB11	Transformers Company/Conversions	1005	66.9	98	155.4	Active	I
BFB12	Company Transformer Purchases 2012	2105	0		0	Active	I
BFO10	TRANSFORMER - COMPANY	205	0		0	Closed 2/2011	I
BGB11	Transformer Customer Requirements	1006	613.1	615	818.5	Active	C
BGB12	Transformer Requirements - Customer 2012	2106	0		0	Active	C
BGC11	Transformer Customer Requirements, Carryover	206	10.7	434	88.6	Completed 2/2011	C
BHB11	Meter Blanket Company Requirements	1008	179.6	179.6	39.6	Active	M
BHB12	Meter Requirements - Company/AMR 2012	2108	0		0	Active	M
BHO10	Meter Requirements - Company/AMR	208	0		-29.9	Closed 2/2011	M
BIB11	Meter Blanket Customer Requirements	1007	173	173	92.4	Active	C
BIB12	Meter Requirements - Customer 2012	2107	0		0	Active	C
BIO10	Meter Requirements - Customer	207	0	117.5	75.4	Closed 2/2011	C
		Sub-Totals:	2,875.20	5,266.70	2,644.90		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS ELECTRIC						
ECE01	Two Way Radio Replacements	1015	3	3	2.6	Active	O
ECE02	AMI Equipment, Unanticipated Replacements	1014	37.5	39.5	34.9	Active	O
		Sub-Totals:	40.5	42.5	37.5		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS GENERAL						
ECC01	Outage Management System (OMS)	9059	100	667.5	92.3	Active	O
ECN01	Outsource Payment Process to Kubra	1030	0	15.1	0	Active	O
ECN02	Bill Print redesign & outsource	1031	0	4.2	1	Active	O
ECN03	Website Phase 2	1032	0	33.8	39.7	Active	O
ECN04	Infrastructure	1034	0	59.3	24.4	Active	O
ECN05	Call Center	1035	0	5.3	1	Active	O
ECN06	MDS Fitchburg Rollout	1036	0	25.4	20.9	Active	O
ECN07	Power Plant	1037	0	107.7	117.6	Active	O
ECN10	CIS Enhancement Project	1040	0	14.8	31.6	Active	O
ECN11	April Fools Day Storm 2011	1065	0		0	Closed 10/2011	O
ECN12	2010 Telecom, Network and Systems Infrastr Upgrade	1089	0		129.4	Closed 11/2011	O
ECN13	Oct 29th Storm Event #111029-SYS-4-11-106	1097	0		561.5	Active	O
ECN14	GIS Upgrade to 9.3	1098	0	2.9	1.8	Active	O
ECN15	EMIS Enhancements	1099	0	0.6	0.1	Active	O
ECN16	Capital Budget System Enhancements	1100	0	0.3	0	Active	O
ECN17	Cash Systems Enhancements	1101	0	1.1	0.3	Active	O

Electric Category	2011
Growth	
Customer Additions (C)	1,385,500
Subtotal Growth	1,385,500
Non-Growth	
Reliability (R)	74,300
Maintenance Replacement (M)	1,804,800
Mandated (H)	232,900
System Improvement (I)	1,509,400
Other (O)	1,282,100
Subtotal Non-Growth	4,903,500
Total	6,289,000
	6,289,000
	0

Budget Category	
Annual Requirements Blankets	**2011**
T&D Improvements	648,400
New Customer Additions	194,600
Outdoor Lighting	70,500
Emergency & Storm Restoration	479,600
Billable work	11,800
Transformers	1,062,500
Meters	177,500
Sub-Totals:	**2,644,900**
Distribution	
Overhead Line Extensions over $20,000	29,800
Underground Line Extensions over $20,000	86,200
Street Light Projects	-
Telephone Company Requests	-
Highway Projects	232,900
Distribution Pole Replacements	395,500
Specific Projects: Distribution	948,200
Sub-Totals:	**1,692,600**
Substation	
Specific Projects: Substation	777,200
Sub-Totals:	**777,200**
Communications	**1,103,500**
Tools, Shop, Garage	**38,900**
Laboratory	**5,800**
Office	**3,800**
Structures	**22,300**
Distribution Totals:	**6,289,000**

CONSTRUCTION BUDGET 2011 Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
ECN18	EDI Data Transfers	1102	0	7.2	1.5	Active	O
ECN20	Thanksgiving Storm	1104	0		24.7	Active	M
ECO02	Two Way Radio Replacements	224	0		0	Closed 2/2011	O
ECO03	AMI Equipment, Unanticipated Replacement	212	0		0	Closed 2/2011	O
ECO04	AMI Communication Trouble Call Response	256	0		6.2	Closed 3/2011	O
ECO05	CIS 2010 Projects	238	0	37.3	8.7	Completed 1/2011	O
ECO06	Unitil Website	248	0		3.3	Closed 2/2011	O
	Sub-Totals:		100	982.4	1,066.00		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	DISTRIBUTION ELECTRIC						
DAB00	Overhead Line Extensions		44.7		25.6	Active	C
DAB01	Three Phase, Temp O/H Line Ext, 152 South Street, Concord	1018	0		-7.6	Active	
DAB02	N Spring St & Rumford St, Concord-Kimball School	1075	0		-6	Completed 12/2011	
DAB03	83 Appleton St, Concord-Customer	1079	0	10.1	4.3	Active	
DAB04	Old Suncook Rd, Concord-Customer	1080	0	40.6	38.2	Completed 12/2011	
DAB05	Dame Eastman School, Curtisville Rd, Concord	1084	0		-8.4	Active	
DAB06	Single Phase, O/H Line Ext to Primary URD, Silk Farm Rd, Nonbillable	1087	0	22.5	-0.6	Active	
DAB07	St. Paul's School Pole Relocation-Pleasant St & Rectory Rd	1088	0		5.6	Completed 12/2011	
DAB08	16 Portsmouth St, Concord-relocate pole	1094	0		0.1	Completed 12/2011	
DAC00	Overhead Line Extensions - Carryover		19.5		4.2	Completed 7/2011	C
DAC01	Relocation of Poles, 45-49 S Main St, Concord	252	0		4.2	Completed 7/2011	
DAO01	Pole Relocations	247	0		10.7	Closed 11/2011	C
DBB00	Underground Line Extensions		77		77.3	Active	C
DBB01	Three Phase Ug Line Ext 45-49 South Main St Concord	1029	0	11.8	13.4	Completed 7/2011	
DBB02	Three phase Ug line ext for 119 Hall St	1033	0	5.2	5.8	Active	
DBB03	Primary Single Phase Underground Line Extension, 16 Nesbitt Dr, Bow	1044	0	1.9	0.7	Completed 6/2011	
DBB04	River Rd, Bow-One Pole 3 phase OH Line Extension-single phase	1073	0	6.3	0.1	Completed 9/2011	
DBB05	Route 3A, Bow 2 Pole 3 phase line extension-single phase	1074	0	9.5	1.5	Completed 10/2011	
DBB07	15A Branch Londonderry Trpk, Bow-Customer	1082	0	9.7	-0.5	Completed 12/2011	
DBB08	Three ph urd line ext-Crescent St, Penacook-Customer	1083	0	33.7	48.7	Completed 12/2011	
DBB09	Three Phase Urd Ext-The Dollar Store-Loudon Rd	1085	0	9.4	13.6	Completed 12/2011	
DBB10	3 ph line ext-Felix Septic Serv-7-9 Ryan Rd, Bow	1086	0	4.3	9.6	Active	
DBB11	175 Manchester St-Concord Nissan 3 ph Primary Underground	1092	0	9	6.9	Active	
DBB13	Scales Rd, Canterbury-line extension-billable	1095	0		-9.6	Active	
DBB14	Route 3A, Bow Water Tower Urd Primary Line Ext-Billable	1096	0	9.5	-16.8	Active	
DBB15	70 N Pembroke Rd, Concord urd line ext-billable	1105	0		3.8	Active	
DBC00	Underground Line Extensions, Carryover		14.3		10.1	Completed 7/2011	C
DBC01	Three Phase, urd line ext, 30 Pembroke Rd, Concord	254	0		0	Closed 1/2011	
DBC02	Overhead Single Phase Guaranteed Line Extension	257	0		10.1	Closed 11/2011	
DBO01	URD Line Ext, Dunbarton Rd, Conc, St Pauls School	245	0		-7.7	Closed 2/2011	C
DBO02	URG Ext-Parmenter Pl, Conc	9053	0		-4.2	Closed 3/2011	C
DCB00	Street Light Projects		13.9			Active	M
DCC00	Street Light Projects - Carryover		4			Completed 5/2011	M
DDB00	Telephone Company Requests		34.9			Active	H
DDC00	Telephone Company Request - Carryover		4.2			Completed 5/2011	H
DEB00	Highway Projects	1041	193.6		232.9	Active	H
DEB01	Relocation of Street Lights at Rte 4 at Harris Hill Road, Boscawen	1070	0		18.5	Completed 10/2011	
DEB02	Relocate 15 poles, Concord	1041	0	64.5	88	Active	
DEB04	Manchester St., Concord - Road Reconstruction	1090	0	185.7	126.5	Active	
Dec-00	Highway Projects, Carryover		5.5			Completed 5/2011	M
DPB01	Condemned Poles (REP)	1013	335.3		385.8	Closed 11/2011	M
DPB02	Purchase Voltage Regulators	1027	90.9	90.9	45.6	Active	I
DPB04	Circuit 4X1, Upgrade Stepdowns at pole 51 Village St	1068	26.1	26.1	24.4	Completed 10/2011	I
DPB05	Circuit 13W2 - Install Voltage Regulator on Water St	1042	23.3	23.3	18.1	Closed 12/2011	I
DPB06	Circuit 18W2 - Install Voltage Regulators on Woodhill Rd	1043	33.2	33.2	23.4	Active	I
DPB07	Bow Junction S/S, New Circuit 7W4	1045	298.1	298.1	316.1	Active	I
DPB10	Extend circuit 1H5 to Theatre St	1078	141.7	155.7	128.2	Active	M
DPB01	Condemned Pole Replacements	2211	0		0	Active	M
DPC01	New 34.5 kV Line Garvins to Bow Junction	8066	187.1	2,269.00	192.1	Completed 8/2011	I
DPC02	Purchase Easement - 396 Line	226	5.5		4.8	Closed 3/2011	O
DPC03	38 Line Load Break and Remote Control Switching Device	9041	27.1	80	0.8	Active	M

Electric Category	2011

Budget Category

CONSTRUCTION BUDGET 2011 Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DPN01	Hall St., Concord - Circuit 7X1 Conversion	1064	0	77.4	80.4	Closed 9/2011	I
DPN02	Broken Pole due to Wind Event on Hazen Dr, Concord	1071	0	22.5	22	Closed 8/2011	M
DPN03	Hurricane Irene	1091	0		8.1	Active	M
DPO01	Condemned Pole Replacements	217	0		9.7	Closed 2/2011	M
DPO02	Purchase Voltage Regulators	242	0	44.7	0	Closed 8/2011	I
DPO03	Circuit 1H6 Reconductoring along 374 ROW	225	0	246.6	4.4	Completed 5/2011	I
DPO04	Birchdale Rd, Bow-Replace recls coils - Cir 22W3	233	0		0	Closed 1/2011	M
DPO05	Horse Hill Rd., Pen-Add 2 Ph, Upgrade reg	231	0		0	Closed 2/2011	I
DPO06	Replace Recloser	9042	0		5.5	Closed 3/2011	M
DRB00	Reliability Projects (REP)		77.2		70.3	Active	R
DRB08	Sewalls Falls Rd., Concord - Install (3) Reclosers	1077	0		29.6	Closed 11/2011	
DRB14	N Main St, Penacook Cir 4X1 Extension-Reliability Improvement	1069	0		40.7	Closed 11/2011	
DRC00	Reliabilty Projects, Carryover		0			Completed 5/2011	R
DRO01	Install three-phase recl	9055	0		4	Closed 11/2011	R
	Sub-Totals:		1,657.30	3,801.40	1692.6		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE ELECTRIC						
EAE01	Purchase and Replace Hot Line Tools	1022	2.5	2.5	0.6	Active	O
EAE03	Tools, Shop & Garage - Normal Additions and Replacements	1020	12	12	14.8	Active	O
EAE04	Purchase and Replace Rubber Goods	1021	3.5	3.5	3.9	Active	O
EAE05	Normal additions & replacement - tools & equipment EM&C	1023	7	7	8.7	Active	O
EAE06	Replace Battery Operated crimping tool	1019	1.8	1.8	2.8	Closed 9/2011	O
EAE07	Purchase Burndy PAT750CXT18VBattery Operated crimping tool	1026	3.5	3.5	3.2	Completed 5/2011	O
EAE16	Replace Laptop - Substation	1024	4	4	2.3	Closed 9/2011	O
EEO02	CAPITAL - AMI AUGMENTATION	8010	0		0	Closed 2/2011	O
	Sub-Totals:		34.3	34.3	36.3		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE GENERAL						
EAN01	Manhole Barricade and Hoist	1076	0	5	4.3	Completed 9/2011	O
EAO01	Purchase and replace Hot Line tools	218	0		0	Closed 2/2011	O
EAO02	Purchace and Replace rubber goods	219	0		0	Closed 2/2011	O
EAO03	Normal Add and Replace Tools and Equip EM&C	213	0		0	Closed 2/2011	O
EAO04	Purchase 6 sets of Overhead grounds	222	0		0	Closed 2/2011	O
EAO05	Tools,shop & garage normal adds and replace	220	0		-1.7	Closed 2/2011	O
	Sub-Totals:		0	5	2.6		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	LABORATORY GENERAL						
EBB01	Lab Equipment - Normal Additions and Replacements	1025	7	7	5.8	Active	O
EBO01	Lab Equip Normal Add and Replace EM&C	214	0		0	Closed 2/2011	O
	Sub-Totals:		7	7	5.8		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE ELECTRIC						
EDE01	Office Furniture & Equipment-Normal Additions and Replacements	1012	3.5	3.5	3.8	Active	O
	Sub-Totals:		3.5	3.5	3.8		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE GENERAL						
EDO02	Office Furniture and Equipment	221	0		0	Closed 2/2011	O
	Sub-Totals:		0	0	0		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	STRUCTURES GENERAL						
GPB01	Normal Improvements to Capital Facility	1010	12	12	12.4	Active	O
GPB03	Replace Room Dividers in Dng/Mtg Room	1016	12	12	9.9	Completed 8/2011	O
GPB04	Install fire strobe lights at designated rooms	1017	5	5	0	Cancelled 12/2011	O
GPO01	Normal Improvements to Captial DOC facility	223	0		0	Closed 2/2011	O
GPO02	Install Backup A/C Unit in Data/Tel Room	232	0		0	Closed 1/2011	O
	Sub-Totals:		29	29	22.3		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	

Electric Category	2011		Budget Category

CONSTRUCTION BUDGET 2011 Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	SUBSTATION ELECTRIC						
SPB01	Bow Junction S/S - 7W4 Circuit Position	1011	613.7		649.5	Closed 11/2011	I
SPB14	Bow Junction S/S - Install 5th TCU		122.9			Cancelled 10/2011	O
SPB16	Hollis S/S - Upgrade Underfrequency Relaying	1067	21.4	21.4	3.1	Active	O
SPC01	Build 34.4-13.8 kV Mobile Substation	251	25.7	131.2	19.9	Completed 8/2011	O
SPC02	Iron Works Road - Install Capacitor Banks	243	50.5	125.4	50.8	Active	O
SPC03	Replace 1H3 Breaker	8073	26.2	53.3	0.1	Active	O
SPC04	15W2 West Portsmouth Street and 2H1 West Concord Breaker Changeouts	259	12.1		0	Closed 3/2011	O
SPC05	Replace Damaged Equip at Pleasant St S/S Concord	6066	32.7	67	3.9	Active	O
SPN01	13X4 Recloser	1028	0	68.4	3.2	Completed 11/2011	O
SPN02	Depot Street, Boscawen Substation	1072	0	54.8	46.7	Active	O
SPO01	Replace 33 Line Breaker	9044	0		0	Closed 1/2011	O
		Sub-Totals:	905.4	521.5	777.2		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TRANSPORTATION ELECTRIC						
1-Feb	Replace Vehicle #6		0			Closed 9/2011	O
2-Feb	Replace pickup #48		0			Closed 11/2011	O
3-Feb	Replace pickup #55		0			Completed 6/2011	O
		Sub-Totals:	0	0	0		
		Grand Totals:	5,652.20	10,693.30	6,289.00		

Electric Category	2011

Budget Category

CONSTRUCTION BUDGET 2011 Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	?? ??						
BABE12	Transformer PCB Removal	2000	0		0	Active	M
BBBE12	Overhead Services	2001	0		0	Active	M
BCBE12	replace 50whps P99/15	2002	0		0	Active	M
BDBE12	Emergency & Storm Restoration	2003	0		0	Active	M
BEBE12	Billable Work	2004	0		0	Active	M
DPBE12	Condemned Poles	2110	0		0	Active	M
		Sub-Totals:	0	0	0		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	BLANKETS ELECTRIC						
BAB11	T&D Improvements	1000	960.9	908.7	852.3	Active	M
BAC11	T&D Improvements, Carryover	200	69.5	1,149.00	82.1	Active	M
BAO09	T&D	9000	0		-10.1	Closed 3/2011	M
BBB11	New Customer Additions	1001	403.2	401.5	362.7	Active	C
BBC11	New Customer Additions, Carryover	201	17.2	475	31.3	Active	C
BCB11	Outdoor Lighting	1002	213.3	249.5	261.1	Active	M
BCC11	Outdoor Lighting, Carryover	202	4.7	280	15.3	Active	M
BDB11	Emergency & Storm Restoration	1003	523.7	573	506.6	Active	M
BDC11	Emergency & Storm Restoration, Carryover	203	13.3	584.4	-76.2	Active	M
BDO09	Emergency Restoration	9003	0		0	Closed 3/2011	M
BEB11	Billable Work	1004	322.2	323	205.8	Active	M
BEC11	Billable Work, Carryover	204	10.3	342.6	-24.3	Active	M
BEO09	Billable Jobs	9004	0		0	Closed 3/2011	M
BFB11	Transformer Company/Conversion	1005	116.2	116.2	127.5	Active	I
BFB12	Transformer Requirements - Co/Conversions 2012	2005	0		0	Active	I
BFC11	Transformers Company/Conversion Carryover	205	0		2.4	Active	I
BGB11	Transformers Customer Requirements	1006	693.5	693.3	801.1	Active	C
BGB12	Transformer Requirements - Customer 2012	2006	0		0	Active	C
BGC11	Transformer Customer Requirements, Carryover	206	13.9	1,018.60	22.2	Active	C
BHB11	Meter Blanket Company Requirements	1008	226.4	226.4	45.2	Active	M
BHB12	Meter Requirements - Company/AMR 2012	2008	0		0	Active	M
BHO10	Meter Requirements - Company/AMR	208	0		0	Closed 2/2011	M
BIB11	Meter Blanket Customer Requirements	1007	152.2	152.2	108.3	Active	C
BIB12	Meter Requirements - Customer 2012	2007	0		0	Active	C
BIO10	Meter Requirements Customer	207	0	161.2	37.9	Closed 8/2011	C
		Sub-Totals:	3,740.70	7,654.60	3,351.20		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS ELECTRIC						
ECE01	AMI Equipment, Unanticipated Replacement	1047	43.3	43.3	12.4	Active	O
ECE02	Two Way Radio Replacements	1029	5	5	1.6	Active	O
		Sub-Totals:	48.3	48.3	14		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS GENERAL						
ECC01	Outage Management System (OMS)	9086	100	1,012.00	188.7	Active	O
ECN02	Bill Print redesign & outsource	1049	0	6.4	1.6	Active	O
ECN03	Website Phase 2	1050	0	51.8	60.9	Active	O
ECN04	Infrastructure	1051	0	86.6	28.7	Active	O
ECN05	Call Center	1052	0	8.1	1	Active	O
ECN06	MDS Fitchburg Rollout	1053	0	45.8	37.6	Active	O
ECN07	Power Plant	1054	0	157.4	171.8	Active	O
ECN10	CIS Enhancement Project	1057	0	22.6	47.4	Active	O
ECN11	April Fools Day Storm	1063	0		0	Closed 8/2011	M
ECN12	2010 Telecom, Network and Systems Infrastr Upgrade	1089	0		189.5	Closed 11/2011	O
ECN13	Oct 29th Storm Event #111029-SYS-4-11-106	1092	0		2,087.70	Active	M
ECN14	Gis Upgrade to 9.3	1093	0	4.3	2.8	Active	O
ECN15	EMIS Enhancements	1094	0	0.9	0.2	Active	O
ECN16	Capital Budget System Enhancements	1095	0	0.4	0	Active	O
ECN17	Cash System Enhancements	1096	0	1.6	0.5	Active	O
ECN18	EDI Data Transfer	1097	0	10.6	2.1	Active	O
ECN19	CIS Enhancements for Retail Choice	1098	0	22.1	0	Active	O
ECO01	AMI Equipment, Unanticipated Replacement	214	0		8.4	Closed 2/2011	O
ECO02	Two Way Radio Replacements	232	0		0	Closed 2/2011	O
ECO03	Purchase SCADA Terminal	219	0		0	Closed 1/2011	O
ECO04	Sungard 2010 Projects	246	0		11.4	Closed 3/2011	O
ECO05	Unitil Website	252	0		-1.2	Closed 2/2011	O
ECO06	Wind Turbine	8090	0	50	0	Active	O
		Sub-Totals:	100	1,480.60	2,839.10		

Electric Category	2011
Growth	
Customer Additions (C)	1,812,100
Subtotal Growth	1,812,100
Non-Growth	
Reliability (R)	241,700
Maintenance Replacement (M)	4,782,000
Mandated (H)	595,200
System Improvement (I)	1,706,900
Other (O)	1,113,900
Subtotal Non-Growth	8,439,700
Total	10,251,800
	10,251,800
	0

Budget Category	
Annual Requirements Blankets	**2011**
T&D Improvements	924,300
New Customer Additions	394,000
Outdoor Lighting	276,400
Emergency & Storm Restoration	430,400
Billable work	181,500
Transformers	953,200
Meters	191,400
Sub-Totals:	**3,351,200**
Distribution	
Overhead Line Extensions over $20,000	160,300
Underground Line Extensions over $20,000	288,300
Street Light Projects	28,000
Telephone Company Requests	-
Highway Projects	595,200
Distribution Pole Replacements	203,600
Specific Projects: Distribution	1,666,900
Sub-Totals:	**2,942,300**
Substation	
Specific Projects: Substation	950,200
Sub-Totals:	**950,200**
Communications	**2,853,100**
Tools, Shop, Garage	**56,000**
Laboratory	**19,400**
Office	**3,400**
Structures	**76,200**
Distribution Totals:	**10,251,800**

CONSTRUCTION BUDGET 2011 Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	DISTRIBUTION ELECTRIC						
DAB00	Overhead Line Extensions - New Projects		62.1		148.9	Active	C
DAB01	Single Phase, O/H Line Ext, 102 Locke Rd, Hampton	1013	0	4.1	6.7	Closed 8/2011	
DAB02	Three Phase, Overhead Line Ext., 106 Ledge Rd., Seabrook	1067	0	12.5	9.8	Closed 8/2011	
DAB03	Three Phase, Overhead Line Ext., 375 Ocean Blvd., Hampton	1068	0	22.4	21.3	Closed 12/2011	
DAB04	Three Phase, Overhead Line Ext., Exeter Rd., South Hampton	1078	0	37.7	108.6	Active	
DAB05	Remove O/H Service, Install Service Pole and URD Service, 12 Main St., Atkinson	1083	0	1.8	0.4	Active	
DAB06	Single Phase, Overhead Line Ext, off Forrest St, Plaistow	1090	0	14.5	2.1	Active	
DAC00	Overhead Line Extensions, Carryover		35.3		11.4	Active	C
DAC01	Overhead Line Ext., Pond St, Newton	275	0		6.3	Closed 12/2011	
DAC02	Added 2 phases, 80 State Rt 125, KI	9075	0		0	Closed 1/2011	
DAC03	OH Line Ext, 99 Ledge Rd, SE	9090	0		5	Closed 5/2011	
DBB00	Underground Line Extensions - New Projects		173		202.5	Active	C
DBB01	URD Line Ext, Heron Way, Stratham	1011	0	10.8	6.7	Active	
DBB02	Three Phase, URD Line Ext., Pope Rd., Atkinson	1058	0		30.4	Closed 11/2011	
DBB03	Single Phase, URD Line Ext., Hickory Rd., Newton	1060	0	5	3.6	Closed 8/2011	
DBB04	Single Phase, URD Line Ext., Cheney Ln, Danville	1062	0	5.7	5.5	Closed 8/2011	
DBB05	Single Phase, URD Line Ext., LInden Rd., Exeter	1064	0	36.2	44.7	Closed 12/2011	
DBB06	3 ph, urd line ex, off Mill Ln, Seabrook	1069	0	57.1	-9.8	Active	
DBB07	URD Secondary, off Kings Highway, Hampton	1071	0	27.9	7	Active	
DBB08	Single Phase, URD LIne Ext., 84 Farm Ln, Seabrook	1074	0	24.6	14.7	Closed 12/2011	
DBB09	Single Phase, URD Line Ext., Cheney Lane, Lots 1 & 2, Danville	1075	0	8.9	9.2	Closed 12/2011	
DBB10	Three Phase, URD Line Ext., Greenough Rd., Plaistow	1077	0	26.5	34.1	Active	
DBB11	Three Phase, URD Line Ext., 29 Garden Rd., Plaistow	1079	0	17	3.8	Active	
DBB12	Single Phase, URD Line Ext., 434 High St., Hampton	1081	0	32.7	9.6	Active	
DBB13	Single Phase URD Line Ext, Linden Rd., Exeter - Phase 2	1088	0	42.5	43	Closed 12/2011	
DBC00	Underground Line Extensions, Carryovers		145.9		85.8	Active	C
DBC01	URD Line Ext, off Ashbrook Rd, EX	236	0		0	Closed 7/2011	
DBC02	Three Phase, URD Line Ext, Epping Rd., Exeter	242	0		6.8	Closed 4/2011	
DBC04	1 PH, Primary URD LIne Ext., 9 Deer Run, AT	269	0		1.2	Closed 6/2011	
DBC05	3 PH, URD Line Ext, 31 Garden Rd, Plaistow	270	0		-4.3	Closed 6/2011	
DBC06	Three Phase, URD Line Ext, Rocks Rd/Dows Ln, Seabrook	271	0	33.1	9.4	Closed 8/2011	
DBC07	Single Phase, URD Line Ext, 56 Drakeside Rd., Hampton	272	0		17.9	Closed 9/2011	
DBC08	Three Phase, URD Line Ext., Ocean Blvd., Hampton	273	0	5.2	53.3	Closed 8/2011	
DBC09	3 ph, URD Line Ext, Riverwoods Dr, EX	9057	0		0	Closed 1/2011	
DBC10	URD Line Ext, Maple Ave, AT	9073	0		1.4	Closed 2/2011	
DBC11	URD line ext, 59 Portsmouth Ave, EX	9091	0		0	Closed 1/2011	
DBC12	Secondary URD Line, 201 Ocean Blvd, SE	9092	0		0	Closed 1/2011	
DCB00	Street Light Projects		51.6		1.9	Active	M
DCB01	Installation of Street Lights,Rt 111/West Rd/Islad Pond, Atkinson	1018	0		1.9	Closed 12/2011	
DCC00	Street Light Projects, Carryover		24		26.1	Active	M
DCC01	Installation of Street Lights,State Rt 125/Rt 121A, Plaistow	265	0	6.4	26.1	Active	
DDB00	Telephone Company Requests		166.3			Active	H
DDC00	Telephone Requests, Carryover		0			Active	H
DEB00	Highway Projects		95.5		97.9	Active	H
DEB03	State of NH, Relocate Poles, Rt 111/West Rd/Island Pond, Atkinson	1033	0	20	35.1	Closed 12/2011	
DEB04	Replacement of Poles, Ball Rd/Great Pond Rd., Kingston	1076	0	39	24.2	Active	
DEB05	Replacement and Changeover of Poles	1091	0	61.3	38.7	Active	
Dec-00	Highway Projects, Carryover		724.8		497.3	Active	H
DEC01	Relocation of Poles, Rt 125, Plaistow	274	0	701.1	497.3	Closed 12/2011	
DEO01	relocation of urd utilities, I-95 Toll, Hampton	9087	0		0	Closed 1/2011	H
DPB01	Condemned Pole Replacement (REP)	1036	549.7	544.7	487.9	Closed 12/2011	M
DPB02	Regulator Capital Improvements	1035	168	168	173.3	Closed 12/2011	I
DPB03	Create New Circuit 27X2	1059	620.4	475	413.9	Active	I
DPB04	13W1 Old County Road Conversion	1037	60.6		33.3	Closed 6/2011	I
DPB05	Create New Circuit 6W2	1061	62.1	62.1	38.6	Closed 12/2011	I
DPC01	Replace Guinea Road 47X1 Regulators	8046	32.8	70	21.4	Active	I
DPC02	3343/3354 Capacitor Banks	8065	15.7		1.1	Closed 3/2011	M
DPC03	18X1 Load Transfer to 2X2 - Carryover	249	105.9		120.8	Closed 11/2011	I
DPC04	Regulator Capital Improvements - Carryover	233	10.5		19	Closed 2/2011	I
DPC05	22X1 Install Capacitor Bank Kingston Road	234	18.1	43	20.3	Active	M
DPN01	Replace Broken Pole and transfer facilities State Rt 286, Seabrook	1017	0	20.4	20.4	Closed 8/2011	M
DPN03	Replace Broken Poles, Water Street, Exeter	1066	0	50	49.6	Completed 8/2011	M
DPN05	Hurricane Irene	1087	0		56.5	Active	M
DPN09	Emergency Repairs to Faulted URG Cable, Cusack St, Hampton	276	0		47.2	Closed 6/2011	M
DPO01	Condemned Pole Replacement - 2010 - Various Locations	222	0		30.3	Closed 3/2011	M
DPO02	Circuit 6W1 Convert a Portion of South Rd, KE	229	0		0	Closed 2/2011	I

Electric Category	2011

Budget Category

CONSTRUCTION BUDGET 2011 Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DPO03	Circuit 21W1 Convert Salem Rd, AT	221	0		0	Closed 1/2011	I
DPO04	Wind Storm - March 14th, 2010	261	0		0	Closed 1/2011	M
DPO05	Replace the failed 51X1 recloser	268	0	40	44.2	Closed 12/2011	M
DPO06	3348 Transmission Line Repairs	247	0		46.6	Closed 11/2011	M
DPO07	Replace neutral - Correct Stray Voltage	260	0	110	4.4	Completed 8/2011	M
DPO08	RECL/REG CIRCUIT 56X1, KINGSTON	7021	0		0	Closed 1/2011	M
DRB00	Reliability Projects (REP)		422.5		64	Completed 12/2011	R
DRB14	15X1 Install Recloser Folly Mill Road	1046	0	75	64	Closed 12/2011	
DRC00	Reliability projects carry-over		213.8		177.7	Active	R
DRC01	Circuit 22X1 Install a Recloser on Danville Rd, Kingston	254	0		33.8	Closed 12/2011	
DRC02	Circuit 18X1 Install Recloser, Rt 27, Hampton	264	0	100.8	22.6	Closed 12/2011	
DRC03	Circuit 5H2 Install a Recloser on Sweet Hill Rd, Plaistow	255	0	100.1	22	Closed 12/2011	
DRC04	Replace 7X2 Recloser	259	0	100	81.5	Active	
DRC05	Circuit 23X1 Install a Recloser on Mill Lane, Hampton	256	0	101.4	17.9	Closed 12/2011	
DRO01	Pollard Rd, PL Circuit 58X1	9063	0		0	Closed 1/2011	R
		Sub-Totals:	3,758.50	3,314.30	2942.3		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE ELECTRIC						
EAE01	Tools, Shop & Garage – Normal Additions and Replacements	1020	11	11	13.8	Active	O
EAE02	Purchase and Replace Rubber Goods	1021	3.2	3.2	3.2	Active	O
EAE03	Purchase and Replace Hot Line Tools	1022	2.2	2.2	3.4	Active	O
EAE04	Normal additions & replacement - tools & equipment EM&C	1044	10	10	10.1	Active	O
EAE05	Purchase tooling for new truck #2	1027	6.5	6.5	2.9	Active	O
EAE07	Purchase underground grounding equipment	1023	6	6	0	Cancelled 9/2011	O
EAE09	Purchase Hydraulic Compresson Tool	1025	3.5	3.5	3.3	Closed 8/2011	O
EAE14	Purchase Fire Retardent Safety Equipment	1026	15	15	6.9	Active	O
EAE15	Purchase tooling for new truck #5	1043	6.5	6.5	9.1	Active	O
EAE23	Replace Phasing tools	1041	5	5	3.3	Closed 8/2011	O
EEO01	AMI AUGMENTATION	8012	0		0	Closed 3/2011	O
		Sub-Totals:	68.9	68.9	56		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE GENERAL						
EAO01	Tools, Shop & Garage - Normal Additions & Replacements	226	0		0	Closed 2/2011	O
EAO02	Purchase and Replace Rubber Goods	227	0		0	Closed 2/2011	O
EAO03	Purchase and Replace Hot Line Tools	228	0		0	Closed 2/2011	O
EAO04	Normal Add and Replace Tools and Equip EM&C	216	0		0	Closed 2/2011	O
		Sub-Totals:	0	0	0		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	LABORATORY GENERAL						
EBB01	Lab Equipment - Normal Additions and Replacements	1045	7	7	5	Active	O
EBB02	Phone Line Test Equipment	1042	5	5	4.9	Active	O
EBB04	Purchase RM17 Field Test Unit	1040	6	6	7.2	Closed 8/2011	O
EBB07	Purchase 2 EK disconnect devices	1038	5	5	2.3	Completed 10/2011	O
EBO01	Lab Equip Normal Add and Replace EM&C	215	0		0	Closed 2/2011	O
		Sub-Totals:	23	23	19.4		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE ELECTRIC						
EDE01	Office Furniture & Equipment – Normal Additions and Replacements	1028	3.5	3.5	3.4	Active	O
		Sub-Totals:	3.5	3.5	3.4		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE GENERAL						
EDO01	Office Furniture and Equipment	230	0		0	Closed 2/2011	O
		Sub-Totals:	0	0	0		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	STRUCTURES GENERAL						
GPB01	Normal Improvements to Kensington Facility	1014	12	12	11	Active	O
GPB04	Replace Broken Pavement Seacoast DOC	1030	17	17	16.2	Completed 7/2011	O
GPB05	HVAC System Engineering Study - Seacoast	1073	35	35	46.4	Completed 10/2011	O
GPO01	Normal Improvements to Kensington Facility	231	0		2.6	Closed 2/2011	O
		Sub-Totals:	64	64	76.2		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	SUBSTATION ELECTRIC						
SPB01	East Kingston S/S - New 13.8 kV Circuit (S/S Construction)	1015	841.1		756.3	Closed 11/2011	I

Electric Category	2011

Budget Category

CONSTRUCTION BUDGET 2011 Seacoast							
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED							
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
SPB07	Exeter S/S - Replace LTC controls (REP)	1039	58.6	58.6	39.2	Active	O
SPC01	Kingston Substation - System Supply Additions	240	65	224.5	-5	Active	I
SPC02	Guinea Station relaying	7019	176.8	221	2.1	Closed 12/2011	O
SPC03	Replace Circuit 11W1 Recloser	8067	20.5	50.7	0	Closed 12/2011	O
SPC04	Install Capacitor Bank - Westville S/S	8069	10		4.7	Closed 2/2011	O
SPC05	Westville S/S Upgrade Circuit Voltage Regulators	9055	12.8		5.4	Closed 3/2011	I
SPN01	Replace Bushings Timberlane	1082	0	65	73.6	Completed 10/2011	O
SPN02	Portsmouth Avenue S/S Insulator Replacement	1085	0	30	30.4	Completed 11/2011	O
SPN03	Replace the 13X3 recloser	1086	0	70	42.6	Active	O
SPO01	2nd Guinea Capacitor Bank	8052	0		0.9	Closed 3/2011	O
SPO02	Install Cap Banks at E Kingston Sub	8068	0	39.3	0	Closed 8/2011	O
		Sub-Totals:	1,184.90	759.1	950.2		
BUDGET NUMBER	DESCRIPTION	AUTH. NUMBER	BUDGETED AMOUNT	AUTH. AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TRANSPORTATION ELECTRIC						
1-Feb	Replace bucket truck #2		0			Completed 12/2011	O
2-Feb	Replace Truck #18		0			Closed 11/2011	O
3-Feb	Replace Van #5		0			Closed 11/2011	O
4-Feb	Replace Truck #22		0			Closed 11/2011	O
Feb-32	Pickup for new Forester position		0			Closed 11/2011	O
		Sub-Totals:	0	0	0		
		Grand Totals:	8,991.70	13,416.20	10,251.80		

Electric Category	2011		Budget Category

CONSTRUCTION BUDGET 2012 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	?? ??						
XXXC01	Allocation of 2011 OH Balance	2260	0		0	Closed 5/2012	M
		Sub-Totals:	0	0	0		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	BLANKETS ELECTRIC						
BABC12	Electric T&D Improvements	2100	911.9	910	959.7	Active	M
BABC13	Electric T&D Improvements	13100	0		0	Active	M
BACC12	Electric T&D Improvements	1000	29.2	820	97.3	Completed 6/2012	M
BAOC12	Electric T&D Improvements	200	0		-12.7	Closed 6/2012	M
BBBC12	New Customer Additions	2101	289.8	289.8	224.4	Active	C
BBBC13	New Customer Additions	13101	0		0	Active	C
BBCC12	New Customer Additions	1001	29	255	20.1	Completed 6/2012	C
BBOC12	New Customer Additions	201	0		0	Closed 1/2012	C
BCBC12	Outdoor Lighting	2102	118	118	94.6	Active	M
BCBC13	Replace/Remove St Lt Fixtures	13102	0		0	Active	M
BCCC12	Outdoor Lighting	1002	5	95	3.3	Completed 5/2012	M
BCOC12	Outdoor Lighting	202	0		0	Closed 6/2012	M
BDBC12	Emergency & Storm Restoration	2103	606.3	620	410.5	Active	M
BDBC13	Emergency & Storm Restoration	13103	0		0	Active	M
BDCC12	Emergency Restoration	1003	8.4	472.2	-61.7	Active	M
BDOC12	Emergency & Storm Restoration	203	0		0.8	Closed 6/2012	M
BEBC12	Billable Work	2104	192.5	192.5	-41.6	Active	M
BEBC13	Billable Work	13104	0		0	Active	M
BECC12	Billables	1004	4.3	175	268.8	Completed 6/2012	M
BEOC12	Billable Work	204	0		45.9	Completed 1/2012	M
BFBC12	Company Transformer Purchases 2012	2105	67.7	67.7	7.1	Active	I
BFBC13	Transformer Purchases - Company	13105	0		0	Active	I
BFCC12	COMPANY TRANSFORMER	1005	0		0.1	Closed 3/2012	I
BGBC12	Transformer Requirements - Customer 2012	2106	631.7	635	751.6	Active	C
BGBC13	Transformer Purchases - Customer	13106	0		0	Active	C
BGCC12	CUSTOMER TRANSFORMER	1006	13.3		52.5	Closed 3/2012	C
BGOC12	TRANSFORMER CUSTOMER	206	0		-31.9	Closed 4/2012	C
BHBC12	Meter Requirements - Company/AMR 2012	2108	66.8	66.8	68	Active	M
BHBC13	Meter Purchases - Company	13108	0		0	Active	M
BHOC11	Electric Meter Purchases - Company Requirements	1008	0		0	Closed 3/2012	M
BIBC12	Meter Requirements - Customer 2012	2107	112.5	112.5	80.5	Active	C
BIBC13	Meter Purchases - Customer	13107	0		0	Active	C
BIOC11	Electric Meter Purchases - Customer Requirements	1007	0		0.1	Closed 3/2012	C
		Sub-Totals:	3,086.20	4,829.40	2,937.40		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS ELECTRIC						
ECEC01	Two Way Radio Replacements	2221	3	11	1.4	Active	O
ECEC02	AMI Equipment, Normal Replacements EMC	2229	31.9	31.9	3.1	Active	O
		Sub-Totals:	34.9	42.9	4.5		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS GENERAL						
ECBC02	Replace two 9000 Symbol handheld devices EMC	2228	11		7.6	Closed 10/2012	O
ECNC01	2012 Infrastructure	2232	0	162.9	38.3	Active	O
ECNC02	Operation System Enhance	2233	0	12	4.2	Active	O
ECNC03	CIS Investigation	2234	0	182.5	312.9	Active	O
ECNC04	Powel Vegetation Management Software	2235	0	98.6	56.7	Active	O
ECNC05	Vendor System Upgrade	2236	0	9	16	Active	O
ECNC06	Internal Systems Upgrade	2237	0	39.4	13.5	Active	O
ECNC07	Field Data Acq	2238	0	33.6	26	Active	O
ECNC08	EETS Historical Data	2239	0	31.9	0	Active	O
ECNC09	AMI / MDM R&D	2240	0	20.2	0	Active	O
ECNC10	Vegetation Mgt UPC	2241	0	47.1	56.2	Active	O
ECNC11	Accounting Sys Enhancements	2244	0	13.4	6	Active	O
ECNC12	Power Plan Property Tax and Asset Lease Module	2255	0	96	52.9	Active	O
ECNC14	MDS UES DEPLOYMENT	2269	0	55	26.2	Active	O
ECNC15	Oct 29th 2012 Storm Event - 121029-SYS-3-12-103	2274	0		0	Active	M
ECNC19	CIS Enhancements for Retail Choice	1103	0	15.1	18.4	Active	O
ECOC01	ABB OMS Purchase	9059	0	667.5	-580.5	Active	O
ECOC02	Two way Radio Replacements	1015	0		0	Closed 2/2012	O
ECOC03	AMI Equipment, Unanticipated Replacements	1014	0		0.1	Closed 2/2012	O
ECOC04	Outsource Payment Process to Kubra	1030	0		0	Cancelled 1/2012	O
ECOC05	Bill Print redesign & outsource	1031	0	4.2	0.5	Active	O

Electric Category	2012
Growth	
Customer Additions (C)	1,271,100
Subtotal Growth	1,271,100
Non-Growth	
Reliability (R)	680,300
Maintenance Replacement (M)	2,234,600
Mandated (H)	236,700
System Improvement (I)	171,700
Other (O)	663,600
Subtotal Non-Growth	3,986,900
Total	5,258,000
	5,258,000
	0

Budget Category	2012
Annual Requirements Blankets	
T&D Improvements	1,044,300
New Customer Additions	244,500
Outdoor Lighting	97,900
Emergency & Storm Restoration	349,600
Billable work	273,100
Transformers	779,400
Meters	148,600
Sub-Totals:	**2,937,400**
Distribution	
Overhead Line Extensions over $20,000	93,400
Underground Line Extensions over $20,000	80,400
Street Light Projects	-
Telephone Company Requests	-
Highway Projects	236,700
Distribution Pole Replacements	401,900
Specific Projects: Distribution	922,600
Sub-Totals:	**1,735,000**
Substation	
Specific Projects: Substation	463,800
Sub-Totals:	**463,800**
Communications	**45,700**
Tools, Shop, Garage	**37,200**
Laboratory	**6,700**
Office	**100**
Structures	**32,100**
Distribution Totals:	**5,258,000**

CONSTRUCTION BUDGET 2012 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
ECOC06	Website Phase 2	1032	0		0	Closed 4/2012	O
ECOC07	Infrastructure	1034	0		11.6	Closed 11/2012	O
ECOC08	Call Center	1035	0		3.6	Closed 8/2012	O
ECOC09	MDS Rollout	1036	0	25.4	19.9	Active	O
ECOC10	Power Plant	1037	0		12.4	Closed 5/2012	O
ECOC11	CIS Enhancement Project	1040	0	36.9	5.2	Active	O
ECOC12	April Fools Day Storm 2011	1065	0		0	Cancelled 2/2012	M
ECOC13	Oct 29th Storm Event #111029-SYS-4-11-106	1097	0		-57.9	Closed 3/2012	M
ECOC14	GIS Upgrade to 9.3	1098	0	2.9	4.1	Active	O
ECOC15	EMIS Enhancements	1099	0	0.6	1	Active	O
ECOC16	Capital Budget System Enhancements	1100	0	0.3	0.6	Active	O
ECOC17	Cash Systems Enhancements	1101	0		0.5	Closed 11/2012	O
ECOC18	EDI Data Transfers	1102	0		5.3	Closed 11/2012	O
ECOC19	Thanksgiving Storm	1104	0		-20.1	Closed 7/2012	M
ECOC20	CIS 2010 Projects	238	0		0	Active	O
		Sub-Totals:	11	1,554.40	41.2		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	DISTRIBUTION ELECTRIC						
DABC00	Overhead Line Extensions		57		49.9	Active	C
DABC01	Guaranted line extension along a maintain town road	2251	0		36.9	Closed 10/2012	
DABC03	1 Pole Line Extension, 13 Dow Rd, Bow-Billable	2262	0	11.1	13	Completed 11/2012	
DACC00	Overhead Line Extensions - Carryover		14		43.5	Completed 9/2012	C
DACC01	Three Phase, Temp O/H Line Ext, 152 South Street, Concord	1018	0		7	Closed 9/2012	
DACC02	N Spring St & Rumford St, Concord-Kimball School	1075	0		6.1	Closed 10/2012	
DACC03	83 Appleton St, Concord-Customer	1079	0		3.4	Closed 1/2012	
DACC04	Old Suncook Rd, Concord-Customer	1080	0		-0.5	Closed 1/2012	
DACC05	Dame Eastman School, Curtisville Rd, Concord	1084	0		7.2	Closed 7/2012	
DACC06	Single Phase, O/H Line Ext to Primary URD, Silk Farm Rd, Nonbillable	1087	0		17.5	Closed 9/2012	
DACC07	St. Paul's School Pole Relocation-Pleasant St & Rectory Rd	1088	0		2.3	Closed 11/2012	
DACC08	16 Portsmouth St, Concord-relocate pole	1094	0		0.3	Closed 5/2012	
DACC09	Relocation of Poles, 45-49 S Main St, Concord	252	0		0	Completed 2/2012	
DBBC00	Underground Line Extensions		96.1		42.9	Active	C
DBBC01	152 South St,Concord-Conant Sch-3 ph primary urd ext	2212	0		8.1	Closed 10/2012	
DBBC02	N Spring St, Concord-Kimball Sch-3 ph primary urd line ext	2213	0		9.8	Closed 8/2012	
DBBC03	S Curtisville Rd, Concord-Dame Sch-3 ph primary urd line ext	2214	0	7.9	11.1	Completed 9/2012	
DBBC05	153 Loudon Rd, Concord-3 ph primary urd line extension	2243	0		9.9	Closed 10/2012	
DBBC06	urd line extension-4 Hardy Ln, Boscawen	2268	0	11.9	7.1	Active	
DBBC07	Outdoor Lighting-Jonathan Dr, Concord	2275	0		-3.1	Active	
DBCC00	Underground Line Extensions, Carryover		24.8		37.5	Completed 6/2012	C
DBCC01	Three Phase Ug Line Ext 45-49 South Main St Concord	1029	0	11.8	0.1	Completed 2/2012	
DBCC02	Three phase Ug line ext for 119 Hall St	1033	0		1.7	Closed 3/2012	
DBCC03	Primary Single Phase Underground Line Extension, 16 Nesbitt Dr, Bow	1044	0		1.3	Closed 10/2012	
DBCC04	River Rd, Bow-One Pole 3 phase OH Line Extension-single phase	1073	0		3.2	Closed 1/2012	
DBCC05	Route 3A, Bow 2 Pole 3 phase line extension-single phase	1074	0		4.8	Closed 7/2012	
DBCC06	15A Branch Londonderry Trpk, Bow-Customer	1082	0		0.6	Closed 3/2012	
DBCC07	Three ph urd line ext-Crescent St, Penacook-Customer	1083	0		-4.9	Closed 5/2012	
DBCC08	Three Phase Urd Ext-The Dollar Store-Loudon Rd	1085	0		-2.8	Closed 1/2012	
DBCC09	3 ph line ext-Felix Septic Serv-7-9 Ryan Rd, Bow	1086	0		-2.3	Closed 3/2012	
DBCC10	175 Manchester St-Concord Nissan 3 ph Primary Underground	1092	0		2.5	Closed 2/2012	
DBCC11	Scales Rd, Canterbury-line extension-billable	1095	0		15.8	Closed 8/2012	
DBCC12	Route 3A, Bow Water Tower Urd Primary Line Ext-Billable	1096	0		19.4	Closed 7/2012	
DBCC13	70 N Pembroke Rd, Concord urd line ext-billable	1105	0		-1.9	Closed 9/2012	

Electric Category	2012

Budget Category

CONSTRUCTION BUDGET 2012 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DCBC00	Street Light Projects		16.9			Active	M
DCCC00	Street Light Projects - Carryover		0			Completed 2/2012	M
DDBC00	Telephone Company Requests		44.5			Active	H
DDCC00	Telephone Company Request - Carryover		5.3			Completed 5/2012	H
DEBC00	Highway Projects		349.8		183.7	Active	H
DEBC01	Pole Relocations for Route 3, Concord Highway Improvements	2246	0	154.7	142.6	Active	
DEBC02	Broken Bridge Rd., Concord - Road Relocation	2242	0		27	Completed 7/2012	
DEBC03	Relocation of Aluminum Light Standards and Removal of Hi Mast	2254	0		5.7	Active	
DEBC04	Relocation of 9 poles along road way-Town of Epsom Request	2259	0		8.5	Closed 10/2012	
DECC00	Highway Projects, Carryover		15.4		53	Active	H
DECC01	Relocation of Street Lights at Rte 4 at Harris Hill Road, Boscawen	1070	0		-18.5	Closed 7/2012	
DECC02	N State St, Concord-pole relocations for Route 3 improvement	1041	0		-0.2	Closed 9/2012	
DECC03	Manchester St., Concord - Road Reconstruction	1090	0	185.7	71.7	Active	
DPBC01	Condemned Pole Replacements	2211	411.1	411.1	401.9	Active	M
DPBC06	Circuit 2H1: Extend Primary & Balance Load		20			Cancelled 11/2012	I
DPBC07	Cir 4X1 - Reconductor and Balance Load	2256	29.6		31.3	Closed 11/2012	I
DPBC08	Circuit 37X1: Install Voltage Regulator		60.6			Cancelled 10/2012	I
DPNC01	Extend Three Phase Along Dow Road - 2166'	2258	0	119.9	146.4	Active	I
DPNC02	Replace failed primary URD cable	2263	0		34.5	Closed 7/2012	M
DPNC04	Replacing Failed Underground - Memorial Field	2272	0		30.3	Closed 11/2012	M
DPOC01	Purchase regulators for 2011 load driven projects	1027	0		0.4	Closed 10/2012	I
DPOC02	Uprade stepdowns to 500kVA on pole 21 Village St., Penacook	1068	0		0.2	Closed 7/2012	I
DPOC04	Woodhill Road, Bow Circuit 18W2 Install (2) voltage regulators	1043	0		0.7	Closed 3/2012	I
DPOC05	New Circuit 7W4 from Bow Junction S/S	1045	0		0	Closed 2/2012	I
DPOC06	Theatre St., Concord - Extend Circuit 1H5	1078	0	155.7	1.8	Completed 2/2012	I
DPOC07	New 34.5 kV Line Garvins to Bow Junction	8066	0		-11.8	Closed 2/2012	I
DPOC08	Install new Remote Control Load Break Switch	9041	0	80	11.6	Active	M
DPOC09	Hall St., Concord - Circuit 7X1 Conversion	1064	0		0	Closed 2/2012	I
DPOC10	Broken Pole due to Wind Event on Hazen Dr, Concord	1071	0		0	Closed 2/2012	M
DPOC11	Hurricane Irene	1091	0		1.4	Closed 3/2012	M
DPOC12	Purchase Voltage Regulators	242	0		0	Closed 1/2012	I
DPOC13	Circuit 1H6 Reconductoring along 374 ROW	225	0	246.6	-4.5	Completed 2/2012	I
DRBC00	Reliability Projects		707		680.3	Active	R
DRBC05	Circuit 4X1 / 37 Line Automation	2264	0	247.2	300.1	Active	
DRBC06	Rebuild Boscawen Sub Station Get away	2267	0	603.1	380.2	Active	
DRCC00	Reliabilty Projects, Carryover		0			Completed 4/2012	R
		Sub-Totals:	1,852.00	2,246.80	1735		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE ELECTRIC						
EAEC01	Tools, Shop & Garage - Normal Additions and Replacements	2223	12.5	12.5	16.1	Active	O
EAEC02	Purchase and replace rubber goods	2224	5	5	5.2	Active	O
EAEC03	Purchase and replace Hot Line Tools	2225	3	3	1.4	Active	O
EAEC04	Normal Additions & replacement - tools & equipment EMC	2226	7	7	6.4	Active	O
EAEC07	Purchase Battery Operated Crimping Tools	2253	1.1		0.7	Closed 10/2012	O
		Sub-Totals:	28.6	27.5	29.8		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE GENERAL						
EABC01	Purchase URD Grounding and Cutting Equipment	2222	8	8	4.1	Active	O
EACC01	Purchase tools for new bucket truck # 22	2273	3.5	3.5	3.2	Active	O
EAOC01	Purchase and replace Hot Line Tools	1022	0		0	Closed 2/2012	O
EAOC02	Tools, Shop & Garage-Normal Additons and Replacements	1020	0		0.1	Closed 2/2012	O
EAOC03	Purchase and Replace Rubber Goods	1021	0		0	Closed 2/2012	O
EAOC04	Normal Additions and Replacement - tools & equipment EM&C	1023	0		0	Closed 2/2012	O
EAOC05	Replace Battery Operated Crimping Tool	1019	0		0	Closed 2/2012	O
EAOC07	Replace Laptop - Substation	1024	0		0	Closed 2/2012	O
EAOC08	Manhole Barricade and Hoist	1076	0		0	Closed 10/2012	O
		Sub-Totals:	11.5	11.5	7.4		
BUDGET		AUTH	BUDGETED	AUTH	PROJECTED	PROJECT	

Electric Category	2012		Budget Category

CONSTRUCTION BUDGET 2012 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
NUMBER	DESCRIPTION	NUMBER	AMOUNT	AMOUNT	AMOUNT	STATUS	
	LABORATORY GENERAL						
EBBC01	Lab Equipment - Normal Additions and Replacement EMC	2227	7	7	6.7	Active	O
EBOC01	Lab Equipment - Normal Additions & replacements EM&C	1025	0		0	Closed 2/2012	O
	Sub-Totals:		7	7	6.7		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE ELECTRIC						
EDEC01	Office Furniture and Equipment-Capital	2219	3.5	3.5	0	Active	O
	Sub-Totals:		3.5	3.5	0		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE GENERAL						
EDOC01	Office Furniture & Equipment Normal Additions & Replace	1012	0		0.1	Closed 1/2012	O
	Sub-Totals:		0	0	0.1		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	STRUCTURES GENERAL						
GPBC01	Capital - Electrical System/Life Safety Upgrades		38			Active	O
GPBC03	Normal Improvements to Capital Facility	2220	12	12	11.1	Active	O
GPBC04	Parking Lot/Pavement Improvements	2217	16		13.9	Closed 10/2012	O
GPBC05	Purchase Automatic External Defibrillator (AED)	2247	2.3		2.6	Closed 5/2012	O
GPNC01	Construct PCB Containment area	2252	0	5.7	4.5	Active	O
GPOC01	Normal improvements to Capital faciltiy	1010	0		0	Closed 2/2012	O
GPOC02	Replace Room Dividers in Dng/Mtg Room	1016	0		0	Closed 1/2012	O
	Sub-Totals:		68.3	17.7	32.1		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	SUBSTATION ELECTRIC						
SPBC03	Upgrade Underfrequency Relaying - West Concord	2248	23.4		12.3	Closed 10/2012	O
SPBC04	Upgrade underfrequency Relaying - Gulf	2249	23.4	23.4	5.4	Completed 11/2012	O
SPBC07	Concord Steam Generator installation		0			Active	C
SPBC14	Replace 8X3, 8X5 Recloser Controls - Hollis	2250	61.5		45.7	Closed 10/2012	O
SPBC17	Replace Station Batteries - Bow Junction S/S EMC	2230	8.3	8.3	3.6	Completed 9/2012	O
SPCC01	Pleasant St S/S - Replace Damaged RTU	2266	118.4	118.4	82.9	Completed 11/2012	O
SPCC03	Replace 1H3 Breaker	8073	27.9	53.3	24.1	Completed 11/2012	O
SPNC01	Iron Works 22T1 Rewind	2231	0	269.6	204.8	Active	O
SPNC03	Hollis 8T1 LTC: replace contacts	2271	0	101	54.4	Active	O
SPOC01	Upgrade Underfrequency Relaying	1067	0		0	Closed 4/2012	O
SPOC03	Install Capacitor Bank	243	0	125.4	0.6	Active	O
SPOC04	13X4 Recloser	1028	0		30	Closed 10/2012	O
SPOC05	Depot Street, Boscawen Substation	1072	0	54.8	0	Active	O
SPOC06	REP DAMG PLEASANT ST S/S, CONCORD	6066	0		0	Closed 8/2012	O
	Sub-Totals:		263	754.3	463.8		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TRANSPORTATION ELECTRIC						
FEBC01	Replace pickup #44		0			Completed 4/2012	O
FEBC02	Replace bucket truck #22		0			Completed 12/2012	O
	Sub-Totals:		0	0	0		
	Grand Totals:		5,366.10	9,495.10	5,258.00		

Electric Category	2012

Budget Category

CONSTRUCTION BUDGET 2012 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	BLANKETS ELECTRIC						
BABE12	Electric T&D Improvements	2000	1,131.90	1,065.70	1,119.00	Active	M
BABE13	Electric T&D Improvements	13000	0		0	Active	M
BACE12	Electric T&D Improvements	1000	97.3	908.7	77.8	Active	M
BAOE11	Electric T&D Improvements	200	0		0	Closed 6/2012	M
BBBE12	New Customer Additions	2001	438.8	360	439.6	Active	C
BBBE13	New Customer Additions	13001	0		0	Active	C
BBCE12	New Customer Additions	1001	34.9		7.7	Closed 10/2012	C
BCBE12	Outdoor Lighting	2002	337.9	335	262.9	Active	M
BCBE13	Outdoor Lighting	13002	0		0	Active	M
BCCE12	Outdoor Lighting	1002	12.8	249.5	-6.5	Closed 10/2012	M
BDBE12	Emergency & Storm Restoration	2003	667	587.4	361.1	Active	M
BDBE13	Emergency & Storm Restoration	13003	0		0	Active	M
BDCE12	Emergency Restoration	1003	17.5	573	18.2	Active	M
BEBE12	Billable Work	2004	365.7	362	374	Active	M
BEBE13	Billable Work	13004	0		0	Active	M
BECE12	Billables	1004	14.4	323	63.2	Active	M
BEOE11	Billable Work	204	0		-6	Closed 10/2012	M
BFBE12	Transformer Requirements - Co/Conversions 2012	2005	586	586	584.3	Active	I
BFBE13	Transformer Purchases - Company Conversions	13005	0		0	Active	I
BFCE12	COMPANY TRANSFORMER	1005	2.7		0.1	Closed 3/2012	I
BGBE12	Transformer Requirements - Customer 2012	2006	702.6	1,132.20	1,349.00	Active	C
BGBE13	Transformer Purchase - Customer	13006	0		0	Active	C
BGCE12	CUSTOMER TRANSFORMER	1006	18.3		23.9	Closed 3/2012	C
BHBE12	Meter Requirements - Company/AMR 2012	2008	164.3	164.3	135.7	Active	M
BHBE13	Electric Meter Purchases - Company	13008	0		0	Active	M
BHOE11	Electric Meter Purchases - Company Requirements	1008	0		15.7	Closed 5/2012	M
BIBE12	Meter Requirements - Customer 2012	2007	187	187	44.3	Active	C
BIBE13	Electric Meter Purchases - Customer	13007	0		0	Active	C
BIOE11	Electric Meter Purchases - Customer Requirements	1007	0		14.5	Closed 3/2012	C
		Sub-Totals:	4,779.30	6,833.90	4,878.50		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS ELECTRIC						
ECEE01	AMI Equipment, Unanticipated Replacement	2128	31.9	31.9	6.4	Active	O
ECEE02	Two Way Radio replacements	2131	5	5	1	Active	O
ECEE06	Seacoast Radio Deskset Replacement		1.2			Active	O
ECEE10	Add AMI Switching Group	2177	48	63	12.6	Active	O
ECEE11	UES Seacoast GIS Realignment	2133	55	55	112.1	Active	O
		Sub-Totals:	141.2	155	132.1		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS GENERAL						
ECNE01	Oct 29th 2012 Storm Event - 121029-SYS-3-12-103	2180	0		343.9	Active	M
ECOE01	ABB OMS Purchase	9086	0	1,012.00	939.4	Active	O
ECOE02	AMI Equipment, Unanticipated Replacement	1047	0		0	Closed 2/2012	O
ECOE03	Two Way Radio Replacements	1029	0		0	Closed 2/2012	O
ECOE04	Bill Print redesign & outsource	1049	0	6.4	0.8	Active	O
ECOE05	Website Phase 2	1050	0		0	Closed 4/2012	O
ECOE06	Infrastructure	1051	0		16.3	Closed 11/2012	O
ECOE07	Call Center	1052	0		6.1	Closed 8/2012	O
ECOE08	MDS Rollout	1053	0	45.8	35.3	Active	O
ECOE09	Power Plant	1054	0		18.1	Closed 5/2012	O
ECOE10	CIS Enhancement Project	1057	0	56.4	8.8	Active	O
ECOE11	April Fools Day Storm	1063	0		0	Cancelled 1/2012	M
ECOE12	Oct 29th Storm Event #111029-SYS-4-11-106	1092	0		-1,609.30	Closed 3/2012	M
ECOE13	Gis Upgrade to 9.3	1093	0	4.3	6.4	Active	O
ECOE14	EMIS Enhancements	1094	0	0.9	1.4	Active	O
ECOE15	Capital Budget System Enhancements	1095	0	0.4	0.3	Active	O
ECOE16	Cash System Enhancements	1096	0		0.7	Closed 11/2012	O
ECOE17	EDI Data Transfer	1097	0		7.8	Closed 11/2012	O
ECOE18	CIS Enhancements for Retail Choice	1098	0	22.1	27	Active	O
ECOE19	Wind Turbine	8090	0		0	Closed 2/2012	O
		Sub-Totals:	0	1,148.30	-197		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	DISTRIBUTION ELECTRIC						
DABE00	Overhead Line Extensions over $20,000		88.4		16.6	Active	C
DABE01	Three Phase Service, 6 Church St., Kingston	2113	0		8	Closed 5/2012	
DABE02	Relocation of Phases, 27 Atlantic Ave., Seabrook	2147	0		11.6	Closed 10/2012	
DABE03	Replacement of Three (3) Poles, Brentwood Rd., Exeter	2153	0	29.2	20.4	Completed 9/2012	
DABE04	Three Phase, OH Line Ext., 337 Lafayette Rd., Seabrook	2155	0		8.5	Closed 8/2012	
DABE05	Relocation of Poles, 380 Lafayette Rd., Seabrook	2160	0	24	16.9	Active	
DABE06	Install Primary Metering & Release Ownership of Infrastructure	2163	0		-48.8	Completed 10/2012	
DACE00	Overhead Line Extensions over $20,000, Carryover		38		10.9	Active	C
DACE01	Single Phase, O/H Line Ext, 102 Locke Rd, Hampton	1013	0		0	Closed 1/2012	
DACE02	Three Phase, Overhead Line Ext., 106 Ledge Rd., Seabrook	1067	0		0	Closed 1/2012	
DACE04	Three Phase, Overhead Line Ext., Exeter Rd., South Hampton	1078	0		0	Closed 1/2012	
DACE05	Remove O/H Service, Install Service Pole and URD Service, 12 Main St., Atkinson	1083	0	1.8	0	Completed 8/2012	
DACE06	Single Phase, Overhead Line Ext, off Forrest St, Plaistow	1090	0		10.9	Closed 2/2012	
DBBE00	Underground Line Extensions over $20,000		222.3		270.7	Active	C
DBBE01	Three Phase, URD Line Ext. White Oak Dr., Exeter	2112	0		17.5	Closed 7/2012	

Electric Category	2012
Growth	
Customer Additions (C)	2,328,500
Subtotal Growth	2,328,500
Non-Growth	
Reliability (R)	140,700
Maintenance Replacement (M)	1,725,800
Mandated (H)	173,000
System Improvement (I)	1,931,300
Other (O)	1,409,000
Subtotal Non-Growth	5,379,800
Total	7,708,300
	7,708,300
	0

Budget Category	
Annual Requirements Blankets	**2012**
T&D Improvements	1,196,800
New Customer Additions	447,300
Outdoor Lighting	256,400
Emergency & Storm Restoration	379,300
Billable work	431,200
Transformers	1,957,300
Meters	210,200
Sub-Totals:	**4,878,500**
Distribution	
Overhead Line Extensions over $20,000	27,500
Underground Line Extensions over $20,000	401,900
Street Light Projects	-
Telephone Company Requests	-
Highway Projects	173,000
Distribution Pole Replacements	573,500
Specific Projects: Distribution	1,510,100
Sub-Totals:	**2,686,000**
Substation	
Specific Projects: Substation	114,400
Sub-Totals:	**114,400**
Communications	**(64,900)**
Tools, Shop, Garage	**52,400**
Laboratory	**7,500**
Office	**1,900**
Structures	**32,500**
Distribution Totals:	**7,708,300**

CONSTRUCTION BUDGET 2012 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DBBE02	Single Phase, URD Line Ext., off Witch Ln., Plaistow	2139	0		17.4	Closed 9/2012	
DBBE03	Three Phase, URD Line Ext., Epping Rd., Exeter, The Meeting Place	2140	0		27.3	Closed 8/2012	
DBBE04	Single Phase, URD Line Ext., Oak Hill Dr., Newton	2142	0		23.2	Completed 3/2012	
DBBE05	Single Phase, URD Line Ext., off Hunt Rd., Hampstead	2150	0		40.7	Closed 8/2012	
DBBE06	Single Phase, Underground Line Ext., 64 Drinkwater Rd, Hampton	2151	0		4.4	Closed 10/2012	
DBBE07	Three Phase, URD Line Ext., 96 Plaistow Rd., Plaistow	2157	0		34.6	Completed 8/2012	
DBBE08	Three Phase, URD Line Ext., 11 Continental Dr., Exeter	2158	0		25.6	Completed 11/2012	
DBBE09	Three Phase, URD Line Ext., 45 Portsmouth Ave., Stratham	2159	0		16.5	Closed 10/2012	
DBBE10	Three Phase, URD LIne Ext., Puzzle Ln, Newton	2162	0		23.6	Closed 9/2012	
DBBE11	Single Phase, URD Line Ext., off Rt 125, Kingston	2165	0	111.8	47.9	Active	
DBBE12	Single Phase, URD Line Ext, Sargent Woods, Newton - Phase 3	2171	0		53.9	Completed 11/2012	
DBBE13	Three Phase, URD Line Ext., 105 Towle Farm Rd., Hampton	2175	0	49.9	-31.3	Active	
DBBE14	Three Phase, URD Line Ext., Drakeside Rd., Hampton	2176	0	42.4	2.9	Active	
DBBE15	Three Phase, URD Line Ext, 83-91 Ocean Blvd., Hampton	2178	0	21.9	-13	Active	
DBBE16	Three Phase, URD Line Ext., 380 Lafayette Rd, Seabrook	2179	0		-20.7	Active	
DBCE00	Underground Line Extensions over $20,000, Carryover		191.7		131.2	Active	C
DBCE01	URD Line Ext, Heron Way, Stratham	1011	0		3	Closed 7/2012	
DBCE02	Single Phase, URD Line Ext., Hickory Rd., Newton	1060	0		0	Closed 1/2012	
DBCE03	Single Phase, URD Line Ext., Cheney Ln, Danville	1062	0		0	Closed 1/2012	
DBCE05	Single Phase, URD Line Ext., Scamman Ln, Stratham	1069	0		81.4	Closed 3/2012	
DBCE06	URD Secondary, off Kings Highway, Hampton	1071	0		16.4	Closed 5/2012	
DBCE09	Three Phase, URD Line Ext., Greenough Rd., Plaistow	1077	0		-5.1	Closed 1/2012	
DBCE10	Three Phase, URD Line Ext., 29 Garden Rd., Plaistow	1079	0		12.7	Closed 3/2012	
DBCE11	Single Phase, URD Line Ext., 434 High St., Hampton	1081	0		22.9	Closed 3/2012	
DBOE01	Three Phase, URD Line Ext, Rocks Rd/Dows Ln, Seabrook	271	0		0	Closed 1/2012	C
DBOE02	Three Phase, URD Line Ext., Ocean Blvd., Hampton	273	0		0	Closed 1/2012	C
DCBE00	Street Light Projects		70.5			Active	M
DCCE00	Street Light Projects, Carryover		13.1			Active	M
DCOE01	Installation of Street Lights,State Rt 125/Rt 121A, Plaistow	265	0		-9.7	Closed 6/2012	M
DDBE00	Telephone Company Requests		216.7			Active	H
DDCE00	Telephone Company Requests, Carryover		0			Active	H
DEBE00	Highway Projects		282.8		154.9	Active	H
DEBE01	Relocate Facilities, Rt. 107/Laf Rd., Seabrook		0			Cancelled 10/2012	
DEBE02	Replacement of Poles, Newfields Rd., Exeter	2121	0		26.6	Closed 5/2012	
DEBE03	Installation of Street Lights, Rt 107/I-95	2164	0		-1	Active	
DEBE04	Relocation of Poles, Epping Road, Exeter	2173	0	22.3	129.3	Active	
Dec-00	Highway Projects, Carryover		68.4		18.1	Active	H
DECE02	Replacement of Poles, Ball Rd/Great Pond Rd., Kingston	1076	0		16.7	Closed 11/2012	
DECE03	Replacement and Changeover of Poles	1091	0		1.4	Closed 3/2012	
DPBE01	Condemned Poles	2110	519	519	573.5	Active	M
DPBE03	Circuit 6W2 Rock Rimmon Road Conversion, Kingston	2132	489.1		279.3	Closed 10/2012	I
DPBE04	Circuit 2X2 Install Voltage Regulators on Landing Rd	2111	82.6		78	Closed 9/2012	I
DPBE05	Circuit 6W1 Relocate North Road East Kingston Voltage Regulator	2134	36.2		0	Cancelled 2/2012	I
DPBE06	Circuit 7X2 Install Voltage Regulator on Collins Street Seabrook	2136	55.7		51.6	Closed 8/2012	I
DPBE07	Convert Circuit 11W1 to Circuit 11X1 - 34.5 kV	2149	833	550	632	Active	I
DPBE14	Circuit 23X1 Install Voltage Regulators on True Road Seabrook	2137	113.4		89.4	Closed 8/2012	I
DPBE15	Circuit 58X1E Upgrade Forest Street Plaistow Stepdown	2135	28.7		20.9	Closed 11/2012	I
DPBE99	Condemned Poles 2011 carryover	1036	0		0.3	Closed 1/2012	M
DPCE01	Replace Guinea Rd 47X1 Regs	8046	35.4	70	0.9	Active	I
DPNE01	Overhead Line Ext., Hemlock St., Exeter	2148	0		20.1	Closed 7/2012	C
DPNE04	Reconductor and Convert, North Rd, East Kingston	2168	0	88.5	88.5	Completed 10/2012	I
DPNE05	Extend Primary and Secondaries, Chase St, Kingston	2169	0	38.2	34.1	Active	I
DPNE06	Installation of Regulator, Huckleberry Lane, Hampton	2170	0		38.7	Closed 11/2012	I
DPNE07	Reconductor Muddy Pond Rd, Kensington	2174	0	103.9	14.4	Active	I
DPOE03	Circuit 19X3 Load Transfer to Circuit 27X2, Court St., Exeter	1059	0	475	18.9	Active	I
DPOE05	Circuit 22X1 Install Capacitor Bank on Kingston Road	234	0	43	0.3	Active	M
DPOE06	Replace Broken Pole and transfer facilities State Rt 286, Seabrook	1017	0		0	Closed 1/2012	M
DPOE07	Replace Broken Poles, Water Street, Exeter	1066	0		0	Closed 1/2012	M
DPOE08	Hurricane Irene	1087	0		11.3	Closed 3/2012	M
DPOE10	Replace neutral - Correct Stray Voltage	260	0		0.4	Closed 2/2012	M
DRBE00	Reliabilty Projects		117.8		130.9	Active	R
DRBE08	Circuit 19X3 - Install Sectionalizers	2145	0		20.2	Closed 8/2012	
DRBE09	Circuit 3H2/3H3 - Increase Phase Spacing	2146	0		36.6	Closed 11/2012	
DRBE12	Install Reclosers, Main Street, Newton	2154	0		34.1	Closed 11/2012	
DRBE13	Install cutouts/fuses on unprotected main line laterals, Various Locations	2172	0		40	Completed 11/2012	
DRCE00	Reliabilty Projects, Carryover		0			Active	R
DROE04	Replace 7X2 Recloser	259	0	100	9.8	Completed 10/2012	R
		Sub-Totals:	3,502.70	2,291.00	2686		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE ELECTRIC						
EAEE01	Normal Additions and Replacements of Tools & Equipment	2114	12.5	12.5	15.1	Active	O
EAEE02	Purchase and Replace Rubber Goods	2115	5	5	4.7	Active	O
EAEE03	Purchase and Replace Hot Line Tools	2122	3	3	3.4	Active	O
EAEE04	Normal additions & replacement - tools & equipment Meter and Services	2127	7	7	5.6	Active	O
EAEE06	Replace 1 kV Meg-Ohm tester	2138	5		5.6	Closed 10/2012	O
EAEE10	Purchase Tooling for new Truck #25	2123	4	4	3	Active	O
EAEE11	Purchase Underground Grounding and Cutting Equipment	2124	8	8	4.3	Active	O
EAEE15	Purchase Battery Operated Crimping Tools	2125	5.5		6	Closed 10/2012	O
		Sub-Totals:	50	39.5	47.7		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE GENERAL						

Electric Category	2012

Budget Category

CONSTRUCTION BUDGET 2012 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
EACE01	Purchase/Replace Tooling for Truck #8		4			Cancelled 7/2012	O
EAOE01	Tools, Shop & Garage - Normal Additions and Replacements	1020	0		0.3	Closed 2/2012	O
EAOE02	Purchase and Replace Rubber Goods	1021	0		0	Closed 2/2012	O
EAOE03	Purchase and Replace Hot Line Tools	1022	0		0	Closed 2/2012	O
EAOE04	Normal additions & replacements - tools & equipment EM&C	1044	0		1	Closed 3/2012	O
EAOE05	Purchase tooling for new truck #2	1027	0		3.4	Closed 9/2012	O
EAOE06	Purchase underground grounding equipment	1023	0		0	Closed 1/2012	O
EAOE07	Purchase Hydraulic Compression Tool	1025	0		0	Closed 1/2012	O
EAOE08	Purchase Fire Retardent Safety Equipment	1026	0		0	Closed 2/2012	O
EAOE09	Purchase Tooling for new truck #5	1043	0		0	Closed 2/2012	O
		Sub-Totals:	4	0	4.7		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	LABORATORY GENERAL						
EBBE01	Lab Equipment - Normal Additions and Replacements	2129	7	7	7.5	Active	O
		Sub-Totals:	7	7	7.5		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE ELECTRIC						
EDEE01	Office Furniture and Equipment-Seacoast	2116	3.5	3.5	1.9	Active	O
		Sub-Totals:	3.5	3.5	1.9		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	STRUCTURES GENERAL						
GPBE01	Normal improvements to Seacoast facility	2126	15	15	12.4	Active	O
GPBE02	Seacoast - Electrical System/Life Safety Upgrades		35			Active	O
GPBE03	HVAC Replacements	2118	11		11.4	Closed 10/2012	O
GPBE04	Purchase Automatic External Defibrillator (AED)	2141	2.3		1.9	Closed 5/2012	O
GPNE01	Construct PCB Containment Area	2152	0	7.5	5.9	Active	O
GPOE01	Normal improvements to Seacoast Facility	1014	0		0.9	Closed 2/2012	O
GPOE03	Boiler Replacement and MEP Work	1073	0		0	Closed 3/2012	O
		Sub-Totals:	63.3	22.5	32.5		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	SUBSTATION ELECTRIC						
SPBE04	Westville - Upgrade Underfrequency Relaying	2144	23.4		23.5	Closed 9/2012	O
SPBE05	Mill Lane Tap - Upgrade Underfrequency Relaying	2143	30.8		29.8	Closed 10/2012	O
SPBE06	Replace the 54X1 recloser	2130	42.5	42.5	46.7	Active	O
SPCE01	Kingston - System Supply Addition	240	162.5	224.5	0.2	Active	I
SPOE01	Exeter S/S Replace LTC Controls (REP)	1039	0	58.6	4.4	Active	O
SPOE04	Replace Bushings Timberlane	1082	0		0.8	Closed 3/2012	O
SPOE05	Portsmouth Avenue S/S Insulator Replacement	1085	0		0.2	Closed 4/2012	O
SPOE06	Replace the 13X3 recloser	1086	0		8.8	Closed 9/2012	O
SPOE07	Install Cap Banks at E Kingston Sub	8068	0		0	Active	O
		Sub-Totals:	259.2	325.7	114.4		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TRANSPORTATION ELECTRIC						
FEBE01	Replace Bucket Truck #25		0			Active	
FEBE05	Replace pickup #35		0			Completed 5/2012	
		Sub-Totals:	0	0	0		
		Grand Totals:	8,810.20	10,826.30	7,708.30		

Electric Category	2012

Budget Category

CONSTRUCTION BUDGET 2013 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Totals	Electric Category
	BLANKETS ELECTRIC							
BABC13	Electric T&D Improvements	13100	799.2	820	737.3	Active	737.3	M
BABC14	T & D Improvements	140100	0		0	Active	0	M
BACC13	Electric T&D Improvements	2100	25.8	910	-18.6	Completed 5/2013	-18.6	M
BAOC13	Electric T&D Improvements	1000	0	820	-1.3	Closed 3/2013	-1.3	M
BBBC13	New Customer Additions	13101	235.2	235.2	242.5	Active	242.5	C
BBBC14	New Customer Additions	140101	0		0	Active	0	C
BBCC13	New Customer Additions	2101	23.9	289.8	-0.6	Closed 12/2013	-0.6	C
BBOC13	New Customer Additions	1001	0		-0.7	Closed 2/2013	-0.7	C
BCBC13	Replace/Remove St Lt Fixtures	13102	87.4	90.7	87.2	Active	87.2	M
BCCC13	Outdoor Lighting	2102	4.1	118	12.9	Completed 2/2013	12.9	M
BCOC13	Outdoor Lighting	1002	0	95	-1.2	Completed 2/2013	-1.2	M
BDBC13	Emergency & Storm Restoration	13103	561.2	561.2	471.1	Active	471.1	M
BDBC14	Ice Storm Dec 22	140103	0		0.1	Active	0.1	M
BDCC13	Emergency & Storm Restoration	2103	7.5	620	-3.8	Completed 10/2013	-3.8	M
BDOC13	Emergency Restoration	1003	0	472.2	0.6	Closed 2/2013	0.6	M
BEBC13	Billable Work	13104	241.5	271.7	312.5	Active	312.5	M
BEBC14	Dec 22 Ice Storm	140104	0		0	Active	0	M
BECC13	Billable Work	2104	7.7	192.5	256.8	Cancelled 10/2013	256.8	M
BEOC13	Billables	1004	0	175	-38.6	Completed 2/2013	-38.6	M
BFBC13	Transformer Purchases - Company	13105	65.9	65.9	54.7	Active	54.7	I
BFBC14	Transformer Purchase-Company	140105	0		0	Active	0	I
BFCC13	Company Transformer Purchases 2012	2105	0		0	Closed 2/2013	0	I
BGBC13	Transformer Purchases - Customer	13106	605.4	685	762.7	Active	762.7	C
BGBC14	URG TRANSF CUSTOMER PURCHASE	140106	0		0	Active	0	C
BGCC13	Transformer Requirements - Customer 2012	2106	12.6		-21.9	Closed 3/2013	-21.9	C
BHBC13	Meter Purchases - Company	13108	65.5	65.5	60.8	Active	60.8	M
BHBC14	Meter Purchase-Company	140108	0		0	Active	0	M
BHOC13	Meter Requirements - Customer 2012	2107	0		0	Closed 2/2013	0	C
BIBC13	Meter Purchases - Customer	13107	113.5	113.5	131.3	Active	131.3	C
BIBC14	Meter Purchase-Customer	140107	0		0	Active	0	C
BIOC13	Meter Requirements - Company/AMR 2012	2108	0	66.8	0	Closed 2/2013	0	M
		Sub-Totals:	2,856.50	6,668.00	3,043.80			

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Totals	
	COMMUNICATIONS ELECTRIC							
ECEC01	AMI Equipment, Normal Replacements	13214	15.5	15.5	1.6	Active	1.6	O
ECEC02	Two Way Radio Replacements	13246	3	3	1.3	Active	1.3	O
ECEC03	NH ESCC RTU Replacement	13293	42	42	14.5	Active	14.5	O
ECEC06	UES Capital Radio Upgrade Project	13241	261.8	261.8	1.4	Active	1.4	O
		Sub-Totals:	322.3	322.3	18.8			

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Totals	
	COMMUNICATIONS GENERAL							
ECNC02	Upgrade Power Plan v10.2.1 to v10.3	13225	0	93.8	80.8	Active	80.8	O
ECNC03	2013 IT Infrastructure	13228	0	119.5	29.5	Active	29.5	O
ECNC04	Company website development	13229	0	32.4	32	Active	32	O
ECNC05	OMS Web Map Improvements	13230	0	10	2.9	Active	2.9	O
ECNC06	Systems Enhancements	13231	0	32.4	13.2	Active	13.2	O
ECNC07	Rate Case Work Flow	13232	0	25.5	19.6	Active	19.6	O
ECNC08	Electric Mobile Data Aquisation	13233	0	51	36.2	Active	36.2	O
ECNC09	OMS Regulatory Reporting	13258	0	27.9	11.7	Active	11.7	O
ECNC10	CIS Replacement	13262	0	1,828.80	0	Active	0	O
ECNC11	Access Control System Upgrades (ACUs)- Enterprise	13280	0	19	18	Active	18	O
ECNC16	MDS UES Deployment	2276	0		0	Active	0	O
ECOC01	ABB OMS Purchase	9059	0		0	Completed 8/2013	0	O
ECOC02	AMI Equipment, Normal Replacements EMC	2229	0		0	Closed 2/2013	0	O
ECOC03	2012 Infrastructure	2232	0		7.1	Closed 6/2013	7.1	O
ECOC04	Operation System Enhance	2233	0		6.6	Closed 4/2013	6.6	O
ECOC05	CIS Investigation	2234	0		-312.9	Cancelled 9/2013	-312.9	O
ECOC06	Powel Vegetation Management Software	2235	0		-56.7	Cancelled 1/2013	-56.7	O
ECOC07	Vendor System Upgrade	2236	0		2.2	Closed 5/2013	2.2	O
ECOC08	Internal Systems Upgrade	2237	0		0.3	Closed 3/2013	0.3	O
ECOC09	Field Data Acq	2238	0		0.5	Closed 3/2013	0.5	O
ECOC10	EETS Historical Data	2239	0		0	Cancelled 8/2013	0	O
ECOC11	AMI / MDM R&D	2240	0		0	Cancelled 9/2013	0	O
ECOC12	Vegetation Mgt UPC	2241	0		-56.2	Cancelled 1/2013	-56.2	O
ECOC13	Accounting Sys Enhancements	2244	0	13.4	5.1	Active	5.1	O
ECOC14	Power Plan Property Tax and Asset Lease Module	2255	0		3.8	Closed 5/2013	3.8	O
ECOC15	MDS UES DEPLOYMENT	2269	0	55	18.2	Active	18.2	O
ECOC16	Oct 29th 2012 Storm Event - 121029-SYS-3-12-103	2274	0		0	Completed 9/2013	0	M

Electric Category	2013
Growth	
Customer Additions (C)	1,155,100
Subtotal Growth	1,155,100
Non-Growth	
Reliability (R)	14,600
Maintenance Replacement (M)	3,059,300
Mandated (H)	47,700
System Improvement (I)	154,800
Other (O)	428,800
Subtotal Non-Growth	3,705,200
Total	4,860,300

4,860,300
0

Budget Category	2013
Annual Requirements Blankets	
T&D Improvements	717,400
New Customer Additions	241,200
Outdoor Lighting	98,900
Emergency & Storm Restoration	468,000
Billable work	530,700
Transformers	795,500
Meters	192,100
Sub-Totals:	**3,043,800**
Distribution	
Overhead Line Extensions over $20,000	51,500
Underground Line Extensions over $20,000	(9,700)
Street Light Projects	-
Telephone Company Requests	-
Highway Projects	47,700
Distribution Pole Replacements	562,100
Specific Projects: Distribution	736,100
Sub-Totals:	**1,387,700**
Substation	
Specific Projects: Substation	401,100
Sub-Totals:	**401,100**
Communications	**(97,800)**
Tools, Shop, Garage	**40,200**
Laboratory	**10,900**
Office	**600**
Structures	**73,800**
Distribution Totals:	**4,860,300**

CONSTRUCTION BUDGET 2013 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Totals	Electric Category
ECOC17	CIS Enhancements for Retail Choice	1103	0		0.2	Closed 3/2013	0.2	O
ECOC18	Bill Print redesign & outsource	1031	0	6.6	4.9	Active	4.9	O
ECOC19	MDS Rollout	1036	0		5.9	Closed 3/2013	5.9	O
ECOC21	GIS Upgrade to 9.3	1098	0		0.8	Closed 4/2013	0.8	O
ECOC22	EMIS Enhancements	1099	0		0	Closed 4/2013	0	O
ECOC23	Capital Budget System Enhancements	1100	0		-0.3	Closed 4/2013	-0.3	O
ECOC24	Two Way Radio Replacements	2221	0		10	Closed 2/2013	10	O
		Sub-Totals:	0	2,315.30	-116.6			
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Totals	
	DISTRIBUTION ELECTRIC							
DABC00	Overhead Line Extensions		50.2		51.5	Active	51.5	C
DABC01	N Pembroke Rd-two pole 3 ph line ext	13212	0	15.7	7.8	Closed 12/2013	7.8	
DABC02	One pole OH Line Extension	13259	0		0.2	Closed 12/2013	0.2	
DABC03	Two additional phases OH then primary urd line extension-Billable	13265	0	31.8	25	Active	25	
DABC04	Three Phase Line Ext - Additional Two Phases - Customer Portion	13272	0	3.2	3.7	Active	3.7	
DABC05	one pole 3 ph OH Line Extension	13277	0	9.8	13.1	Active	13.1	
DABC06	Line extension for OL's	13282	0		2.2	Completed 11/2013	2.2	
DABC08	Relocate Pole for Customer	13287	0		-0.6	Active	-0.6	
DACC00	Overhead Line Extensions - Carryover		10.2		0	Closed 9/2013	0	C
DACC01	1 Pole Line Extension, 13 Dow Rd, Bow-Billable	2262	0	11.1	0	Closed 9/2013	0	
DBBC00	Underground Line Extensions		82.9		-9.8	Active	-9.8	C
DBBC01	Primary underground line extension-45 S Fruit St	13245	0	10.3	2.1	Completed 10/2013	2.1	
DBBC02	Single ph urd line ext for ph 2 for Oxbow Bluff Development	13249	0	30.1	16.5	Completed 10/2013	16.5	
DBBC03	S Curtisville Rd, Concord-Dame Sch-3 ph primary urd line ext	2214	0	7.9	1.5	Closed 2/2013	1.5	
DBBC04	primary 3 ph urd line ext	13260	0		0	Cancelled 5/2013	0	
DBBC05	3 Ph Primary Underground Line Ext	13261	0	14.7	11.3	Closed 12/2013	11.3	
DBBC06	Single ph urd ext for ph 2 for Peaslee Hill Estates	13263	0	37.2	0	Completed 10/2013	0	
DBBC07	Single ph urd line extension for ph 4 Beechwood Estates	13264	0	23.2	17.2	Closed 12/2013	17.2	
DBBC08	Prim urd line ext to a new pad mount transf	13266	0		9.2	Closed 12/2013	9.2	
DBBC09	remove primary OH line ext and replace with primary urd line ext	13268	0		2.2	Active	2.2	
DBBC10	Single ph urd line ext	13269	0	5.3	5.3	Closed 11/2013	5.3	
DBBC11	3 ph primary urd line extension	13274	0	3.3	-4.8	Active	-4.8	
DBBC12	replacing old primary urd with new	13276	0		-50.2	Active	-50.2	
DBBC13	Replacing OH with new urd	13281	0		-1.2	Active	-1.2	
DBBC14	primary urd line ext	13283	0	6.3	-7.7	Active	-7.7	
DBBC15	3ph line ext to a 500KVA pad for service upgrade	13288	0	7.9	3.4	Active	3.4	
DBBC16	Primary urd line extention	13289	0	14.5	-14.5	Active	-14.5	
DBCC00	Underground Line Extensions, Carryover		10.7		0.1	Completed 3/2013	0.1	C
DBCC01	Three Phase Ug Line Ext 45-49 South Main St Concord	1029	0		-1.6	Closed 6/2013	-1.6	
DBCC02	urd line extension-4 Hardy Ln, Boscawen	2268	0		-2	Closed 6/2013	-2	
DBCC03	Outdoor Lighting-Jonathan Dr, Concord	2275	0		3.7	Closed 7/2013	3.7	
DCBC00	Street Light Projects		14.5			Active	0	M
DCCC00	Street Light Projects - Carryover		0			Completed 1/2013	0	M
DDBC00	Telephone Company Requests		38			Active	0	H
DDCC00	Telephone Company Request - Carryover		4.3			Completed 3/2013	0	H
DEBC00	Highway Projects		89.7		37.1	Active	37.1	H
DEBC02	CIP 35 - Corridor Improvements - Village St., Penacook	13237	0	48.4	14.2	Active	14.2	
DEBC03	Reroute Overhead Main Line 4X1 Around Village of Penacook	13273	0		22.9	Active	22.9	
DECC00	Highway Projects, Carryover		0		10.6	Active	10.6	H
DECC01	Pole Relocations for Route 3, Concord Highway Improvements	2246	0	154.7	0.1	Closed 2/2013	0.1	
DECC03	Relocation of Aluminum Light Standards and Removal of Hi Mast	2254	0		0	Active	0	
DECC04	Manchester St., Concord - Road Reconstruction	1090	0	185.7	10.5	Closed 12/2013	10.5	
DPBC01	Distribution Pole Replacement	140109	348.4		562.1	Closed 11/2013	562.1	M
DPBC02	Purchase Voltage Regulators	13227	75.7	75.7	28.7	Active	28.7	I
DPBC04	Replace Grey Spacer cable	13244	457.9	467.4	236.1	Active	236.1	M
DPBC05	Install New Underground Switch, 211P, MH25	13218	51.6	51.6	20.9	Active	20.9	M
DPBC06	4X1: Install Regulator	13236	36.5	36.5	21.8	Closed 10/2013	21.8	I
DPBC07	Recloser Upgrade and Load Balance - Main St., Chichester	13253	11.2	11.2	4.5	Closed 10/2013	4.5	M
DPBC08	Replace Cap Bank on 33 Line - Pleasant St. S/S, Concord	13251	34.6	34.6	27.5	Closed 12/2013	27.5	M
DPBC09	Replace Cap Bank - Hazen Dr., Concord - Pole 39	13252	32	32	42.6	Completed 12/2013	42.6	M
DPBC10	Cir 2H2 - Install regulators and load transfers	13234	44.4	50	49.5	Closed 11/2013	49.5	I
DPBC11	Relocate 33 line and 21W1 along Turkey River	13285	232.3	232.3	126.1	Active	126.1	M
DPBC12	Removal OH Primary Line-683 Route 3A, Bow	13235	0		0.2	Closed 12/2013	0.2	M
DPNC01	MV Accident - Shopping Center Rd., Concord	13255	0	31.6	31.5	Closed 5/2013	31.5	M
DPNC02	Replace failed underground - Fort Eddy Rd., Concord	13278	0	30.6	30.5	Closed 12/2013	30.5	M
DPNC03	Replace Failed UG Cable - Hazen Drive S/S, Concord	13290	0	22.7	22.7	Closed 12/2013	22.7	M
DPNC04	Motor Vehicle Accident - Pole 12X-7 Fort Eddy Rd., Concord	13291	0	26.2	26.2	Closed 12/2013	26.2	M
DPNC05	Replace Primary UG - Pole 6-A - Old Suncook Rd., Concord	13295	0	29.2	29.2	Active	29.2	M
DPNC06	Replaced Failed UG - Morgan Dr., Bow - Pad 1	13299	0	23.3	22.6	Active	22.6	M
DPOC02	Extend Three Phase Along Dow Road - 2166'	2258	0	147.7	0.1	Closed 11/2013	0.1	I

Electric Category	2013		Budget Category

CONSTRUCTION BUDGET 2013 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Totals	Electric Category
DPOC04	Install new Remote Control Load Break Switch	9041	0		0.8	Closed 11/2013	0.8	M
DRBC00	Reliability Projects		10.6		14.6	Active	14.6	R
DRBC06	Install Hydraulic Recloser - Pole 1 - Lake View Rd., Concord	13267	0	10.6	14.6	Closed 11/2013	14.6	
DRCC00	Reliabilty Projects, Carryover		0			Completed 1/2013	0	R
		Sub-Totals:	1,635.70	1,934.40	1387.7			
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Totals	
	TOOLS, SHOP, GARAGE ELECTRIC							
EAEC01	Tools, Shop & Garage - Normal Additions and Replacements Line Dept.	13222	13	13	17	Active	17	O
EAEC02	Purchase Rubber Goods Line Dept.	13224	5	5	5.4	Active	5.4	O
EAEC03	Purchase Hot Line Tools Line Dept.	13223	5	5	5.6	Active	5.6	O
EAEC07	Normal Additions & Replacement - Tools & Equipment EM&C	13216	7	7	6.8	Active	6.8	O
		Sub-Totals:	30	30	34.8			
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Totals	
	TOOLS, SHOP, GARAGE GENERAL							
EACC01	Purchase tools for new truck 21	13300	3.5	3.5	1.1	Closed 5/2013	1.1	O
EANC01	Replace failed voltage recorder	13284	0	3.3	3.3	Active	3.3	O
EAOC01	Purchase URD Grounding and Cutting Equipment	2222	0		1	Closed 10/2013	1	O
EAOC03	Tools, Shop & Garage - Normal Additions and Replacements	2223	0		0	Closed 2/2013	0	O
EAOC04	Purchase and replace rubber goods	2224	0		0	Closed 2/2013	0	O
EAOC05	Purchase and replace Hot Line Tools	2225	0		0	Closed 2/2013	0	O
EAOC06	Normal Additions & replacement - tools & equipment EMC	2226	0		0	Closed 2/2013	0	O
		Sub-Totals:	3.5	6.8	5.4			
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Totals	
	LABORATORY GENERAL							
EBBC01	Lab Equipment - Normal Additions and Replacements EM&C	13215	7		10.9	Closed 10/2013	10.9	O
EBOC01	Lab Equipment - Normal Additions and Replacement EMC	2227	0		0	Closed 2/2013	0	O
		Sub-Totals:	7	0	10.9			
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Totals	
	OFFICE ELECTRIC							
EDEC01	Office Furniture and Equipment	13226	3.5	3.5	0.6	Active	0.6	O
		Sub-Totals:	3.5	3.5	0.6			
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Totals	
	OFFICE GENERAL							
EDOC01	Office Furniture and Equipment-Capital	2219	0		0	Closed 2/2013	0	O
		Sub-Totals:	0	0	0			
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Totals	
	STRUCTURES GENERAL							
GPBC01	Normal Improvements to Capital Facility	13213	12.5	12.5	8.2	Active	8.2	O
GPBC02	Physical Security Additions	13240	41.9	46.1	42.9	Active	42.9	O
GPBC03	CAPITAL - Relocate SCADA Equipment	13248	7.5	10.5	2	Active	2	O
GPBC04	Door Replacements	13242	16	16	11.9	Active	11.9	O
GPCC05	Electrical systems and life safety upgrades	13243	38	38	8.8	Active	8.8	O
GPOC01	Normal Improvements to Capital Facility	2220	0		0	Closed 2/2013	0	O
GPOC02	Construct PCB Containment area	2252	0		0	Closed 2/2013	0	O
		Sub-Totals:	115.9	123.1	73.8			
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Totals	
	SUBSTATION ELECTRIC							
SPBC01	Bridge Street - 35 Breaker Sync-Check Modifications	13270	67.3	10	13.4	Closed 12/2013	13.4	O
SPBC02	Penacook Substation: Replace Control Wiring	13275	66.3	118.3	1.1	Active	1.1	O
SPBC03	Langdon St. Cap and Pin Insulators	13219	44.6	60.6	2.5	Active	2.5	O
SPBC05	Bow Junction Cap and Pin Insulators	13220	9	9	3.3	Active	3.3	O
SPBC06	Bridge Street Substation Install Overvoltage Protection	13254	53.3		64.7	Closed 8/2013	64.7	O
SPBC07	Terrill Park S/S, Replace Station Batteries	13221	11	11	3.9	Completed 9/2013	3.9	O
SPBC08	Penacook S/S - 036 Load Shed Scheme	13271	70.6	70.6	32	Active	32	O
SPCC01	Replace 1H3 Breaker		11.1			Completed 1/2013	0	O

Electric Category	2013		Budget Category

CONSTRUCTION BUDGET 2013 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Totals	Electric Category
SPCC02	Install Capacitor Bank	243	26.3	125.4	13.9	Active	13.9	O
SPNC01	Install returned 22T1 and new equipment	13256	0	239.6	234.9	Closed 12/2013	234.9	O
SPOC01	Upgrade underfrequency Relaying - Gulf	2249	0		11.3	Closed 3/2013	11.3	O
SPOC02	Replace Station Batteries - Bow Junction S/S EMC	2230	0		0	Closed 2/2013	0	O
SPOC03	Pleasant St S/S - Replace Damaged RTU	2266	0		0	Closed 4/2013	0	O
SPOC05	Hollis 8T1 LTC: replace contacts	2271	0		20.1	Closed 5/2013	20.1	O
SPOC06	Depot Street, Boscawen Substation	1072	0		0	Closed 3/2013	0	O
		Sub-Totals:	359.4	644.4	401.1			
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Totals	
	TRANSPORTATION ELECTRIC							
FEBC01	replace bucket 25		0			Active	0	O
FEBC02	Replace plow truck		0			Completed 2/2013	0	O
		Sub-Totals:	0	0	0			
		Grand Totals:	5,333.90	12,047.90	4,860.30			

Electric Category	2013		Budget Category

CONSTRUCTION BUDGET 2013 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	BLANKETS ELECTRIC						
BABE13	Electric T&D Improvements	13000	988.9	1,213.40	1,330.20	Active	M
BABE14	Electric T & D	141000	0		0	Active	M
BACE13	Electric T&D Improvements	2000	92.6	1,065.70	-9.8	Active	M
BAOE13	Electric T&D Improvements	1000	0	908.7	0	Closed 2/2013	M
BBBE13	New Customer Additions	13001	299.4	420.5	445	Active	C
BBBE14	New Customer Overhead Services	141001	0		0	Active	C
BBCE13	New Customer Additions	2001	14.3	439.6	8.4	Active	C
BCBE13	Outdoor Lighting	13002	262.8	262.8	251.8	Active	M
BCBE14	To correct pl rec lighting State Rt -sub	141002	0		0	Active	M
BCCE13	Outdoor Lighting	2002	11.7	335	2.8	Closed 9/2013	M
BDBE13	Emergency & Storm Restoration	13003	472.6	495	453.4	Active	M
BDBE14	Emergency & Storm Prep	141003	0		0	Active	M
BDCE13	Emergency & Storm Restoration	2003	16.2	587.4	-12.7	Closed 9/2013	M
BDOE13	Emergency Restoration	1003	0		0	Closed 2/2013	M
BEBE13	Billable Work	13004	374.3	376.4	300	Active	M
BEBE14	Mutual Aid	141004	0		0	Active	M
BECE13	Billable Work	2004	180.5	362	-13.1	Closed 9/2013	M
BEOE13	Billables	1004	0	323	1.6	Closed 12/2013	M
BFBE13	Transformer Purchases - Company Conversions	13005	522.8	522.8	273.7	Active	I
BFBE14	Transformer Purchase-Company	141005	0		0	Active	I
BFCE13	Transformer Requirements - Co/Conversions 2012	2005	16.8	586	0	Closed 3/2013	I
BGBE13	Transformer Purchase - Customer	13006	812.3	1,009.30	1,072.00	Active	C
BGBE14	Transformer Purchase-Cust Req-URD	141006	0		0	Active	C
BGCE13	Transformer Requirements - Customer 2012	2006	22.7		31.1	Closed 3/2013	C
BHBE13	Electric Meter Purchases - Company	13008	118	118	137.6	Active	M
BHBE14	Meter Purchase-Company	141008	0		0	Active	M
BHOE13	Meter Requirements - Company/AMR 2012	2008	0	164.3	3.9	Closed 3/2013	C
BIBE13	Electric Meter Purchases - Customer	13007	174.1	174.1	207.2	Active	C
BIBE14	Meter Purchase-Customer	141007	0		0	Active	C
BIOE13	Meter Requirements - Customer 2012	2007	0		26.3	Closed 3/2013	C
		Sub-Totals:	4,380.00	9,364.00	4,509.40		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS ELECTRIC						
ECEE01	Two Way Radio Replacements	13149	4	4	2.1	Active	O
ECEE02	AMI Equipment, Unanticipated Replacement	13121	32	32	1.9	Active	O
ECEE03	Replace Seabrook Marsh RTU	13193	20.4	20.4	0	Active	O
ECEE04	UES Radio Upgrade Seacoast	13143	195.8	195.8	1.4	Active	O
		Sub-Totals:	252.2	252.2	5.4		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS GENERAL						
ECNE01	Purchase Lab Equipment for Line Evaluation	13190	0	9	6.7	Active	O
ECOE01	Bill Print redesign & outsource	1049	0	10.1	7.6	Active	O
ECOE02	MDS Rollout	1053	0		8.4	Closed 3/2013	O
ECOE04	Gis Upgrade to 9.3	1093	0		1.2	Closed 4/2013	O
ECOE05	EMIS Enhancements	1094	0		0	Closed 4/2013	O
ECOE06	Capital Budget System Enhancements	1095	0		0.2	Closed 4/2013	O
ECOE07	CIS Enhancements for Retail Choice	1098	0		0.3	Closed 3/2013	O
ECOE08	AMI Equipment, Unanticipated Replacement	2128	0		0	Closed 5/2013	O
ECOE09	Two Way Radio replacements	2131	0		0	Closed 2/2013	O
ECOE10	UES Seacoast GIS Realignment	2133	0		-50.6	Closed 10/2013	O
ECOE11	Add AMI Switching Group	2177	0	63	55.3	Completed 11/2013	O
ECOE12	Oct 29th 2012 Storm Event - 121029-SYS-3-12-103	2180	0		5.7	Closed 12/2013	M
		Sub-Totals:	0	82.1	34.8		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	DISTRIBUTION ELECTRIC						
DABE00	Overhead Line Extensions - New Projects		74.9		180.3	Active	C
DABE01	Three Phase, O/H Line Ext., Kelly St., Plaistow	13117	0	34	27.9	Closed 11/2013	
DABE02	Single Phase, O/H Line Ext, 41 Union Rd., Stratham	13140	0	13.7	13.7	Closed 9/2013	
DABE03	Replace and Changeover Two Poles, Extend Primary	13156	0	20	13.1	Closed 7/2013	
DABE04	Temporary O/H Line Ext, 700 Lafayette Rd., Seabrook	13159	0		1.4	Closed 9/2013	
DABE05	Relocation of Pole, 37 Mill Ln	13163	0		-0.6	Closed 10/2013	
DABE06	Three Phase, O/H Line Ext., 119 Brown Ave., Hampton	13164	0	5.5	8.9	Closed 10/2013	

Electric Category	2013
Growth	
Customer Additions (C)	2,599,000
Subtotal Growth	2,599,000
Non-Growth	
Reliability (R)	580,200
Maintenance Replacement (M)	3,431,700
Mandated (H)	-16,800
System Improvement (I)	4,354,300
Other (O)	363,100
Subtotal Non-Growth	8,712,500
Total	11,311,500

11,311,500
0

Budget Category	
Annual Requirements Blankets	**2013**
T&D Improvements	1,320,400
New Customer Additions	453,400
Outdoor Lighting	254,600
Emergency & Storm Restoration	440,700
Billable work	288,500
Transformers	1,376,800
Meters	375,000
Sub-Totals:	**4,509,400**
Distribution	
Overhead Line Extensions over $20,000	204,300
Underground Line Extensions over $20,000	600,800
Street Light Projects	4,300
Telephone Company Requests	-
Highway Projects	(16,800)
Distribution Pole Replacements	606,400
Specific Projects: Distribution	3,592,300
Sub-Totals:	**4,991,300**
Substation	
Specific Projects: Substation	1,643,300
Sub-Totals:	**1,643,300**
Communications	**40,200**
Tools, Shop, Garage	**41,300**
Laboratory	**6,800**
Office	**1,600**
Structures	**77,600**
Distribution Totals:	**11,311,500**

CONSTRUCTION BUDGET 2013 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DABE07	Replacement & Changeover of Poles, 40 Hampton Rd., Exeter	13165	0	39.4	36.1	Closed 9/2013	
DABE08	Single Phase, O/H Line Ext., 55 Heath St	13171	0	6.2	3.5	Completed 9/2013	
DABE09	Three Phase, O/H Line Ext., 17 Spring St, Exeter	13174	0	25.2	23.1	Closed 11/2013	
DABE10	Single Phase, O/H Line Ext, 13 Old Town Farm Rd	13176	0	16.1	17.8	Closed 11/2013	
DABE11	Three Phase Service, 22 Exeter Rd., South Hampton	13177	0	8.9	10.8	Closed 12/2013	
DABE12	Single Phase, O/H Line Ext., 71 North Rd, Kingston	13180	0	13	10.8	Active	
DABE13	Three Phase O/H Line Ext., 4 Plaistow Rd, Plaistow	13185	0	20.1	13.7	Active	
DACE00	Overhead Line Extensions, Carryover		29.9		24	Active	C
DACE01	Replacement of Three (3) Poles, Brentwood Rd., Exeter	2153	0	29.2	0	Closed 8/2013	
DACE02	Relocation of Poles, 380 Lafayette Rd., Seabrook	2160	0	24	0.7	Closed 2/2013	
DACE03	Install Primary Metering & Release Ownership of Infrastructure	2163	0		22.4	Closed 2/2013	
DACE04	Remove O/H Service, Install Service Pole and URD Service, 12 Main St., Atkinson	1083	0		0.8	Closed 2/2013	
DBBE00	Underground Line Extensions - New Projects		196.4		424.8	Active	C
DBBE01	Three Phase, URD Line Ext., 5-9 Plaistow Rd., Plaistow	13118	0	12	15.9	Closed 10/2013	
DBBE02	Single Phase, URD Line Ext., Bunker Hill Avenue, Stratham	13141	0	55.2	68.9	Completed 10/2013	
DBBE03	Three Phase, URD Line Ext., 700 Lafayette Rd, Seabrook	13151	0	194.2	123.1	Active	
DBBE04	Single Phase, URD Line Ext., Hemlock & Cedar Dr, Newton	13157	0	36.6	39.5	Closed 10/2013	
DBBE05	Single Phase, URD Line Ext., French's Ln, Kensington	13160	0	7.4	7.9	Active	
DBBE06	Single Phase, URD Line Ext., 10 Columbus Ave., Exeter	13167	0	28.7	37.3	Active	
DBBE07	Three Phase, URD Line Ext., 311 Winnacunnet Rd., Hampton	13169	0	9	11	Closed 11/2013	
DBBE08	Single Phase, URD Line Ext., Huntington Hill Rd, Danville	13178	0		3.2	Closed 11/2013	
DBBE09	Three Phase, URD LIne Ext., Sterling Hill, Exeter - Building 6	13181	0	36	53.3	Active	
DBBE10	Single Phase, URD Line Ext., Keefe Ave., Hampton	13186	0	41.4	44	Active	
DBBE11	Single Phase, URD Line Ext., Sargent Woods, Newton - PH 4A	13188	0	27.5	8.8	Active	
DBBE12	Three Phase, URD Line Ext., 339 Ocean Blvd., Hampton	13189	0	43.9	24	Active	
DBBE13	Single Phase, URD Line Ext., Juniper Ln, Hampton	13191	0	30.6	-12.3	Active	
DBCE00	Underground Line Extensions, Carryovers		122.4		176	Active	C
DBCE02	Single Phase, URD Line Ext., off Rt 125, Kingston	2165	0	100.6	-12.3	Active	
DBCE04	Three Phase, URD Line Ext., 105 Towle Farm Rd., Hampton	2175	0		84.1	Closed 9/2013	
DBCE05	Three Phase, URD Line Ext., Drakeside Rd., Hampton	2176	0	42.4	27.5	Closed 10/2013	
DBCE06	Three Phase, URD Line Ext, 83-91 Ocean Blvd., Hampton	2178	0	21.9	32	Closed 9/2013	
DBCE07	Three Phase, URD Line Ext., 380 Lafayette Rd, Seabrook	2179	0	24.7	44.8	Closed 9/2013	
DCBE00	Street Light Projects		53.1			Active	M
DCCE00	Street Light Projects, Carryover		12.3		4.3	Active	M
DCCE01	Installation of Street Lights, Rt 107/I-95	2164	0		4.3	Closed 12/2013	
DDBE00	Telephone Company Requests		93.8			Active	H
DDCE00	Telephone Requests, Carryover		0			Cancelled 1/2013	H
DEBE00	Highway Projects		108.9		0	Active	H
DEBE01	Relocation of Poles, Westside Dr., Atkinson	13162	0	110.8	0	Active	
Dec-00	Highway Projects, Carryover		0			Cancelled 1/2013	H
DEOE02	Relocation of Poles, Epping Road, Exeter	2173	0	112.5	-16.8	Closed 7/2013	H
DPBE01	Distribution Pole Replacement	141010	501.6		606.4	Closed 12/2013	M
DPBE02	Purchase Regulators for Various Distribution Projects	13116	454	454	445	Completed 11/2013	I
DPBE03	Circuit 23X1 Convert Amesbury Rd and Transfer to 27X1 Kensington	13110	577.5		558.2	Closed 10/2013	I
DPBE04	Circuit 19X3 - Reconductor Newfields Road, Exeter	13111	314.6	314.6	173.2	Closed 9/2013	I
DPBE05	Circuit 3W4 - Reconductor Ocean Blvd, Hampton Beach	13131	82	82	62.8	Closed 5/2013	I
DPBE06	Circuit 28X1 - Rebuild Wakeda Campground Lateral, Hampton Falls	13112	142.7	142.7	124.2	Closed 7/2013	M
DPBE07	Circuit 56X1 - Convert Hunt Road, Kingston to 34.5 kV	13113	140.5	140.5	108.2	Closed 10/2013	I
DPBE08	Circuit 43X1 - Convert Route 111/Kingston Rd., Exeter to 34.5 kV	13114	607.8	607.8	495	Completed 9/2013	I
DPBE09	Circuit 21W1 - Reconductor East Road, Atkinson	13115	348.9	348.9	216	Closed 10/2013	I
DPBE10	Install Regulators, Hampton Falls Rd (Rt. 88), Exeter	13133	56.4	56.4	41.7	Closed 11/2013	I
DPBE11	Circuit 5H1 Transfer to 21W1, Plaistow	13132	84.1	92.1	76.2	Completed 11/2013	I
DPBE12	Reconductor 3360 and 3371 Lines - Timber Swamp to Guinea	13155	428.1	428.1	146	Active	I
DPBE13	Install Regulators, Sweet Hill Rd., Plaistow	13134	35.8	35.8	21.7	Closed 7/2013	I
DPBE14	Install Regulators, Exeter Rd. (Rt 111), Kingston	13135	46.2	46.2	22	Closed 7/2013	I
DPBE15	Install Regulators, Various Locations, Atkinson	13136	70.1		44.5	Closed 10/2013	I
DPBE16	Install Regulators, Various Locations, Newton	13137	112.8	111.8	88.2	Closed 7/2013	I
DPBE17	Install Regulator, Forest St, Plaistow	13138	34.9	34.9	10.9	Closed 7/2013	I
DPBE18	Replace the 03341 and the 3352 Reclosers at Wolf Hill	13161	154.6	154.6	90.6	Active	M
DPBE98	Cir. 58X1 Install Regulator, Goodwin Rd	141013	0		0	Active	I
DPCE01	Extend Primary and Secondaries, Chase St, Kingston	2169	19.5	38.2	0.6	Closed 3/2013	M
DPCE02	Reconductor Muddy Pond Rd, Kensington	2174	52.5	103.9	41.7	Closed 3/2013	I
DPCE03	Circuit 19X3 Load Transfer to Circuit 27X2, Court St., Exeter	1059	12.1	475	28	Active	I
DPNE01	Replace and Changeover Damaged Pole - Motor Vehicle Accident	13123	0	28.8	28.7	Closed 4/2013	I
DPNE02	removal of Static wire conductor	13142	0	48	36	Closed 6/2013	M
DPNE03	Circuit 51X1 - Convert Portion of High Street, Stratham	13147	0	65	39.7	Completed 10/2013	M
DPNE04	Structure Replacement on 3342 Sub Transmission Line	13158	0	45	30.6	Closed 12/2013	M
DPNE06	Circuit 58X1 - Convert Newton Road to 34.5 kV	13173	0	228.1	27.7	Active	I
DPNE07	Replacement and Changeover of Poles, Maple Ave, Newton	13187	0	32.6	29	Closed 12/2013	M
DPNE08	Replace and Changeover Pole 141/15	13194	0	22.8	22.8	Active	M

Electric Category	2013		Budget Category

CONSTRUCTION BUDGET 2013 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DPOE02	Convert Circuit 11W1 to Circuit 11X1 - 34.5 kV	2149	0		0	Closed 3/2013	I
DPOE03	Replace Guinea Rd 47X1 Regs	8046	0	70	0	Active	M
DPOE04	Reconductor and Convert, North Rd, East Kingston	2168	0	88.5	0	Closed 2/2013	I
DPOE05	Circuit 22X1 Install Capacitor Bank on Kingston Road	234	0		2.9	Closed 7/2013	I
DRBE00	Reliability Projects		913.7		580.2	Active	R
DRBE01	Fuse Changes to Address Mainline Unfused Laterals & Sensitivity Concerns	13154	0	30	28	Closed 12/2013	
DRBE16	Hampton S/S - Install Protective Devices on 3342, 3353 and 3348	13170	0	645.1	329.7	Active	
DRBE17	Portsmouth Ave S/S - Install Reclosers	13166	0	280.6	222.5	Active	
DRCE00	Reliabilty Projects, Carryover		0			Cancelled 1/2013	R
		Sub-Totals:	5,882.00	6,442.40	4991.3		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE ELECTRIC						
EAEE01	Normal Additions and Replacements of Tools & Equipment	13127	12.5	17.5	19.8	Active	O
EAEE02	Purchase and Replace Rubber Goods	13128	5	5	4.4	Active	O
EAEE03	Purchase and Replace Hot Line Tools	13129	3	3	4.1	Active	O
EAEE04	Normal additions & replacement - tools & equipment Meter and Services	13120	7		10.5	Closed 9/2013	O
		Sub-Totals:	27.5	25.5	38.8		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE GENERAL						
EAOE01	Normal Additions and Replacements of Tools & Equipment	2114	0		0	Closed 2/2013	O
EAOE02	Purchase and Replace Rubber Goods	2115	0		0	Closed 2/2013	O
EAOE03	Purchase and Replace Hot Line Tools	2122	0		0.1	Closed 2/2013	O
EAOE04	Normal additions & replacement - tools & equipment Meter and Services	2127	0		-0.2	Closed 5/2013	O
EAOE05	Purchase Tooling for new Truck #25	2123	0		2.6	Closed 6/2013	O
EAOE06	Purchase Underground Grounding and Cutting Equipment	2124	0		0	Closed 2/2013	O
		Sub-Totals:	0	0	2.5		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	LABORATORY GENERAL						
EBBE01	Lab Equipment - Normal Additions and Replacements	13119	7		8.7	Closed 10/2013	O
EBOE01	Lab Equipment - Normal Additions and Replacements	2129	0		-1.9	Closed 4/2013	O
		Sub-Totals:	7	0	6.8		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE ELECTRIC						
EDEE01	Office Furniture and Equipment	13139	3.5	3.5	1.6	Active	O
		Sub-Totals:	3.5	3.5	1.6		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE GENERAL						
EDOE01	Office Furniture and Equipment-Seacoast	2116	0		0	Closed 2/2013	O
		Sub-Totals:	0	0	0		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	STRUCTURES GENERAL						
GPBE01	Normal Improvements to Kensington Facility	13124	15	15	5.9	Active	O
GPBE02	Physical security upgrades	13144	45.6	50.2	50.6	Active	O
GPBE03	Door Replacements	13145	15	15	14.6	Active	O
GPCE01	Electric system/life safety upgrades	13146	35	35	7.9	Active	O
GPOE01	Normal improvements to Seacoast facility	2126	0		0	Closed 2/2013	O
GPOE02	Construct PCB Containment Area	2152	0		-1.4	Closed 2/2013	O
		Sub-Totals:	110.6	115.2	77.6		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	SUBSTATION ELECTRIC						
SPBE01	Kingston - Site Evaluation, Permitting and Other Preliminary Survey	13184	168.1	12,705.60	107	Active	I
SPBE02	Westville S/S Add Second Transformer	13125	1,328.30	1,328.30	1,200.90	Completed 10/2013	I

Electric Category	2013		Budget Category

CONSTRUCTION BUDGET 2013 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
SPBE03	Replace 3360 and 3371 Breakers at Guinea Sw/S	13148	345.8	345.8	191.8	Active	I
SPBE04	Exeter Sw/S - Raise Motor Operators	13122	22.3	54.9	46.4	Active	O
SPBE05	Hampton Beach S/S - Replace 4 kV Transformer	13175	115.6	135.2	139.3	Active	O
SPOE01	Replace the 54X1 recloser	2130	0	61.3	14	Closed 7/2013	O
SPOE02	Kingston - System Supply Addition	240	0		-57.7	Cancelled 9/2013	I
SPOE03	Exeter S/S Replace LTC Controls (REP)	1039	0	58.6	1.6	Closed 12/2013	O
		Sub-Totals:	1,980.20	14,689.70	1,643.30		

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TRANSPORTATION ELECTRIC						
FEBE01	Replace truck #14		0			Closed 12/2013	O
FEBE02	Replace truck #12		0			Closed 12/2013	O
FEBE03	Replace truck #31		0			Closed 11/2013	O
FEBE04	Replace Wire Trailer		0			Closed 12/2013	O
FEBE05	Replace pole Trailer		6			Closed 12/2013	O
		Sub-Totals:	6	0	0		
		Grand Totals:	12,649.00	30,974.50	11,311.50		

Electric Category	2013		Budget Category

CONSTRUCTION BUDGET 2014 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	BLANKETS ELECTRIC						
BABC14	T & D Improvements	140100	1,051.00	1,032.70	1,083.00	Active	M
BABC15	Electric T & D	150100	0		0	Active	M
BACC14	Electric T&D Improvements	13100	28.9		11	Closed 10/2014	M
BAOC12	Electric T&D Improvements	2100	0		-0.7	Closed 1/2014	M
BAOC13	Electric T&D Improvements	1000	0		0	Closed 3/2014	M
BBBC14	New Customer Additions	140101	255.7	282.7	432.1	Active	C
BBBC15	NewCustomer Additions	150101	0		0	Active	C
BBCC14	New Customer Additions	13101	26.9		1.9	Closed 10/2014	C
BBOC12	New Customer Additions	201	0		0	Closed 2/2014	C
BCBC14	Outdoor Lighting	140102	97.7	97.7	74.5	Active	M
BCCC14	Replace/Remove St Lt Fixtures	13102	3.8		-0.1	Closed 10/2014	M
BCOC12	Outdoor Lighting	202	0		0	Closed 1/2014	M
BCOC13	Outdoor Lighting	1002	0		0	Closed 4/2014	M
BDBC14	Emergency & Storm	140103	610.4	622.3	562.8	Active	M
BDBC15	Replace Broken Cutout - Pole 91 - Route 3A, Bow	150103	0		0	Active	M
BDCC14	Emergency & Storm	13103	7.9		-92	Closed 10/2014	M
BDOC12	Emergency & Storm Restoration	2103	0		-2.3	Closed 2/2014	M
BDOC13	Emergency Restoration	1003	0		0	Closed 4/2014	M
BEBC14	Billable Work	140104	190	191.6	186.7	Active	M
BEBC15	MV Accident	150104	0		0	Active	M
BECC14	Billable Work	13104	13.1		-17.1	Closed 10/2014	M
BEOC05	BILLABLE WORK 2005	5004	0		0	Closed 4/2014	M
BEOC11	Billables	1004	0		0	Closed 1/2014	M
BEOC12	Billable Work	2104	0		0	Closed 3/2014	M
BFBC14	Transformer Purchase-Company	140105	75.7	38.9	3.9	Active	I
BFBC15	2015 Transformer Purchases-Company	150105	0		0	Active	I
BFCC14	Transformer Purchases - Company	13105	2.7		0	Closed 4/2014	I
BGBC14	URG TRANSF CUSTOMER PURCHASE	140106	753.9	547.7	589.8	Active	C
BGBC15	2015 Transformer Purchases-Customer	150106	0		0	Active	C
BGCC14	Transformer Purchases - Customer	13106	14.1		17.9	Closed 4/2014	C
BHBC14	Meter Purchase-Company	140108	77.5	77.5	74.5	Active	M
BHBC15	2015 Meter Purchases-Company	150108	0		0	Active	M
BHOC14	Meter Purchases - Company	13108	0		6.2	Closed 4/2014	C
BIBC14	Meter Purchase-Customer	140107	129.8	129.8	99.4	Active	C
BIBC15	2015 Meter Purchases-Customer	150107	0		0	Active	C
BIOC14	Meter Purchases - Customer	13107	0		-6.2	Closed 4/2014	C
		Sub-Totals:	3,338.90	3,020.90	3,025.30		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS ELECTRIC						
ECEC01	Two Way Radio Replacements	140114	3	3	4.7	Active	O
EECC01	UES Capital Radio Upgrade Project	13241	11		0	Closed 12/2014	O
EECC02	NH ESCC RTU Replacement	13293	11.1	42	23.9	Active	O
		Sub-Totals:	25.1	45	28.6		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS GENERAL						
ECNC01	2014 INFRASTRUCTURE	140126	0	130.4	32.7	Active	O
ECNC03	2014 AMI/SCADA Cyber Project	140128	0	42.8	33.3	Active	O
ECNC04	AMI Version Update and PLX Functionality	140129	0	27	19.7	Active	O
ECNC05	OMS Web Map Improvements	140130	0	4.9	2.7	Active	O
ECNC06	Desktop Client Management	140131	0	22.6	2.1	Active	O
ECNC07	Upgrade Generator Interconnection Database	140141	0	19.6	47.7	Active	O
ECNC08	Electric Inspections	140145	0	60.7	67.1	Active	O
ECNC09	24 Hour Damage Assessment/Field Restoration	140146	0	60.1	18.4	Active	O
ECNC10	General Liability True up to plant assets	140149	0		242.7	Closed 9/2014	O
ECNC11	To move acct 105 to 360 Broken Ground Land	140150	0		762.9	Closed 9/2014	O
ECNC12	General Software Enhancements	140152	0	17.5	9.3	Active	O
ECNC13	Vehicle GIS/Garmin Overlay	140177	0	12.7	5.5	Active	O
ECNC14	Enhancemements to Critical Financial Control Systems	140178	0	49.8	38.9	Active	O
ECNC15	EETS Enhancements	140179	0	8.2	1.2	Active	O
ECOC01	AMI Equipment, Normal Replacements	13214	0		11.7	Closed 2/2014	O
ECOC02	Two Way Radio Replacements	13246	0		0.6	Closed 2/2014	O
ECOC03	Upgrade Power Plan v10.2.1 to v10.3	13225	0		0	Closed 1/2014	O
ECOC04	2013 IT Infrastructure	13228	0		1.5	Closed 5/2014	O
ECOC05	Company website development	13229	0		1.4	Closed 6/2014	O
ECOC06	OMS Web Map Improvements	13230	0		0	Closed 5/2014	O
ECOC07	Systems Enhancements	13231	0		0.3	Closed 7/2014	O
ECOC08	Rate Case Work Flow	13232	0	25.5	1.8	Closed 12/2014	O
ECOC09	Electric Mobile Data Aquisation	13233	0		15.7	Closed 5/2014	O

Electric Category	2014
Growth	
Customer Additions (C)	1,319,300
Subtotal Growth	1,319,300
Non-Growth	
Reliability (R)	11,900
Maintenance Replacement (M)	3,309,900
Mandated (H)	141,200
System Improvement (I)	978,000
Other (O)	1,814,300
Subtotal Non-Growth	6,255,300
Total	7,574,600
	7,574,600
	0

Budget Category	
Annual Requirements Blankets	**2014**
T&D Improvements	1,093,300
New Customer Additions	434,000
Outdoor Lighting	74,400
Emergency & Storm Restoration	468,500
Billable work	169,600
Transformers	611,600
Meters	173,900
Sub-Totals:	**3,025,300**
Distribution	
Overhead Line Extensions over $20,000	16,900
Underground Line Extensions over $20,000	18,400
Street Light Projects	-
Telephone Company Requests	-
Highway Projects	141,200
Distribution Pole Replacements	863,900
Specific Projects: Distribution	795,900
Sub-Totals:	**1,836,300**
Substation	
Specific Projects: Substation	1,268,900
Sub-Totals:	**1,268,900**
Communications	**1,353,100**
Tools, Shop, Garage	**59,100**
Laboratory	**4,000**
Office	**2,700**
Structures	**25,200**
Distribution Totals:	**7,574,600**

CONSTRUCTION BUDGET 2014 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
ECOC10	OMS Regulatory Reporting	13258	0		0	Closed 5/2014	O
ECOC11	CIS Replacement	13262	0		0	Closed 9/2014	O
ECOC12	Access Control System Upgrades (ACUs)- Enterprise	13280	0		0	Closed 8/2014	O
ECOC13	Accounting Sys Enhancements	2244	0		2.5	Closed 1/2014	O
ECOC19	MDS Rollout	1036	0		4.8	Closed 9/2014	O
ECOC99	MDS UES DEPLOYMENT	2269	0		0	Closed 1/2014	O
		Sub-Totals:	0	481.8	1,324.50		

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	DISTRIBUTION ELECTRIC						
DABC00	Overhead Line Extensions		57.4		8.9	Active	C
DABC01	Relocate 3 ph Primary -Robinson Rd Bow	140143	0		-0.2	Closed 9/2014	
DABC02	158 Canterbury Rd Chichester-OH & URD Line Ext-Billable	140160	0	14.7	11.1	Active	
DABC03	42 Little Pond Rd 2 p line extension -Billable	140163	0	10.2	7.3	Closed 12/2014	
DABC04	170 South Rd Salisbury, Four Pole OH Line Extension-Billable	140174	0	9.9	-20	Active	
DABC05	34 Boyce Rd Canterbury, OH to URD Line Extension-Billable	140175	0		4.2	Active	
DABC98	Replace Transf-Penacook St Concord -Billable	140158	0		0	Cancelled 10/2014	
DABC99	Repl Transf Penacook St Concord-Billable	140162	0		6.6	Closed 10/2014	
DACC00	Overhead Line Extensions - Carryover		11.1		8	Completed 3/2014	C
DACC02	Two additional phases OH then primary urd line extension-Billable	13265	0		6.8	Closed 10/2014	
DACC03	Three Phase Line Ext - Additional Two Phases - Customer Portion	13272	0		-2.5	Closed 3/2014	
DACC04	one pole 3 ph OH Line Extension	13277	0		4.3	Closed 9/2014	
DACC05	Line extension for OL's	13282	0		-1.6	Closed 4/2014	
DACC06	Relocate Pole for Customer	13287	0		1	Closed 4/2014	
DBBC00	Underground Line Extensions		95.8		10.4	Active	C
DBBC02	22 S Meadow St Conc-Single Ph Urd Line Ext	140117	0		4.3	Closed 4/2014	
DBBC03	341 Mountain Rd Concord-Primary Underground Line Ext	140137	0	8.4	7.1	Active	
DBBC04	69 Dover Rd -3 ph upgrade	140151	0	15.2	5.7	Completed 11/2014	
DBBC05	urd line ext-7 Goldenrod Ln Concord	140165	0	3.7	5.4	Closed 12/2014	
DBBC07	8 Sterling Lane Bow-Single Phase URD Line Extension	140173	0		-0.6	Closed 12/2014	
DBBC08	Nickerson Dr-Oxbow Bluff Sub Divi Ph 2B Line Extension	140181	0		-11.6	Active	
DBCC00	Underground Line Extensions, Carryover		13.5		150.9	Active	C
DBCC01	Primary underground line extension-45 S Fruit St	13245	0		7.2	Closed 5/2014	
DBCC02	Single ph urd line ext for ph 2 for Oxbow Bluff Development	13249	0		9.7	Closed 10/2014	
DBCC04	Single ph urd ext for ph 2 for Peaslee Hill Estates	13263	0		0	Cancelled 1/2014	
DBCC06	remove primary OH line ext and replace with primary urd line ext	13268	0		-0.8	Closed 1/2014	
DBCC07	3 ph primary urd line extension	13274	0	3.3	7.5	Closed 12/2014	
DBCC08	replacing old primary urd with new	13276	0		91	Active	
DBCC09	Replacing OH with new urd	13281	0		1.3	Closed 4/2014	
DBCC10	primary urd line ext	13283	0		18	Closed 7/2014	
DBCC11	Scales Rd, Canterbury-line extension-billable	1095	0		2.7	Closed 3/2014	
DBCC12	Primary urd line extention	13289	0		14.4	Closed 4/2014	
DCBC00	Street Light Projects		7.9			Active	M
DCCC00	Street Light Projects, Carryover		0			Completed 3/2014	M
DDBC00	Telephone Company Requests		30.7			Active	H
DDCC00	Telephone Company Requests, Carryover		0			Completed 3/2014	H
DEBC00	Highway Projects		96.2		59.7	Active	H
DEBC01	Relocating Poles for City of Concord - S Main St., Concord	140142	0	30.7	22.3	Closed 12/2014	
DEBC02	Pole Replacements for Road Reconstruction - Franklin Rd., Salis	140156	0		36.4	Closed 10/2014	
DEBC03	Pole Relocation for Bridge Replacement - State of NH	140168	0		1.1	Active	
DECC00	Highway Projects, Carryover		21.1		81.5	Active	H
DECC01	Relocation of Aluminum Light Standards and Removal of Hi Mast	2254	0		32.5	Active	
DECC02	Manchester St., Concord - Road Reconstruction	1090	0		0	Closed 1/2014	
DECC03	CIP 35 - Corridor Improvements - Village St., Penacook	13237	0	48.4	39.8	Closed 12/2014	
DECC04	Reroute Overhead Main Line 4X1 Around Village of Penacook	13273	0	29.7	9.1	Active	
DPBC01	Distribution Pole Replacement	140109	686.4	810.7	863.9	Closed 12/2014	M
DPBC02	Goboro Rd., Epsom - Recloser Coil Replacement	140134	7.3		7.5	Closed 6/2014	M
DPBC03	Perley St., Concord - Load Transfer 3H1 to 3H2	140135	69.7	71	75.4	Closed 12/2014	I
DPBC12	Removal OH Primary Line-683 Route 3A, Bow	13235	0		0	Cancelled 1/2014	M
DPCC01	Relocate 33 line and 21W1 along Turkey River	13285	17.1	232.3	130.7	Closed 12/2014	M
DPNC01	Replace Primary UG and Install Pullbox - Tower Hill Rd., Bow	140132	0		59	Closed 4/2014	M
DPNC02	Replaced Failed UG Cable - Pad 3-4 Brookwood Dr., Concord	140147	0		38.8	Closed 10/2014	M
DPNC07	November 24 Wind Storm	13301	0		26.1	Closed 4/2014	M
DPNC08	374 Line Tie to 318 Line - Garvins 115kV Project	140169	0	96.5	57.7	Completed 10/2014	M
DPOC01	Purchase Voltage Regulators	13227	0		0	Closed 2/2014	I
DPOC02	Replace Grey Spacer cable	13244	0		251.9	Closed 5/2014	M
DPOC03	Install New Underground Switch, 211P, MH25	13218	0	51.6	4.9	Active	M
DPOC04	Recloser Upgrade and Load Balance - Main St., Chichester	13253	0		-6.2	Closed 1/2014	M
DPOC05	Replace Cap Bank on 33 Line - Pleasant St. S/S, Concord	13251	0		0	Closed 10/2014	M
DPOC06	Replace Cap Bank - Hazen Dr., Concord - Pole 39	13252	0		-4.7	Closed 2/2014	M
DPOC09	Replace Primary UG - Pole 6-A - Old Suncook Rd., Concord	13295	0		0	Closed 1/2014	M
DRBC00	Reliability Projects		22.1		11.9	Active	R
DRBC02	33 Line Remote Fault Indication at Pleasant Street	140148	22.1	24.5	11.9	Completed 12/2014	

Electric Category	2014		Budget Category

CONSTRUCTION BUDGET 2014 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETE D AMOUNT	AUTH AMOUNT	PROJECTE D AMOUNT	PROJECT STATUS	Electric Category
DRCC00	Reliabilty Projects, Carryover		0			Completed 3/2014	R
		Sub-Totals:	1,158.40	1,460.90	1836.3		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETE D AMOUNT	AUTH AMOUNT	PROJECTE D AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE ELECTRIC						
EAEC01	Tools, Shop & Garage - Normal Additions and Replacements	140122	7	21	14.5	Active	O
EAEC02	Purchase and Replace Rubber Goods	140123	5	5	3	Active	O
EAEC03	Purchase and Replace Hot Line Tools	140124	4.5	4.5	4.5	Active	O
EAEC04	Normal additions & replacement - tools & equipment Metering	140119	5		9.8	Closed 10/2014	O
EAEC05	Replace the FC200 handheld readers	140118	8.9		7.7	Closed 10/2014	O
EAEC99	Normal Addtions and Replacement Tools Substation	140121	7		10.4	Closed 10/2014	O
		Sub-Totals:	37.4	30.5	49.9		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETE D AMOUNT	AUTH AMOUNT	PROJECTE D AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE GENERAL						
EACC01	Purchase tools for new bucket truck # 25	140176	5	5	8.2	Closed 8/2014	O
EAOC01	Tools, Shop & Garage - Normal Additions and Replacements Line Dept.	13222	0		0.5	Closed 2/2014	O
EAOC02	Purchase Rubber Goods Line Dept.	13224	0		0	Closed 2/2014	O
EAOC03	Purchase Hot Line Tools Line Dept.	13223	0		0	Closed 2/2014	O
EAOC04	Normal Additions & Replacement - Tools & Equipment EM&C	13216	0		0.5	Closed 2/2014	O
EAOC05	Replace failed voltage recorder	13284	0		0	Closed 5/2014	O
		Sub-Totals:	5	5	9.2		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETE D AMOUNT	AUTH AMOUNT	PROJECTE D AMOUNT	PROJECT STATUS	
	LABORATORY GENERAL						
EBBC01	Lab Equipment - Normal Additions and Replacements	140120	7	7	4	Active	O
		Sub-Totals:	7	7	4		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETE D AMOUNT	AUTH AMOUNT	PROJECTE D AMOUNT	PROJECT STATUS	
	OFFICE ELECTRIC						
EDEC01	Office Furniture & Equipment-Normal Additions and Replacements	140116	7	7	2.7	Active	O
		Sub-Totals:	7	7	2.7		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETE D AMOUNT	AUTH AMOUNT	PROJECTE D AMOUNT	PROJECT STATUS	
	OFFICE GENERAL						
EDOC01	Office Furniture and Equipment	13226	0		0	Closed 2/2014	O
		Sub-Totals:	0	0	0		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETE D AMOUNT	AUTH AMOUNT	PROJECTE D AMOUNT	PROJECT STATUS	
	STRUCTURES GENERAL						
GPBC01	Nomal Improvemnts to Capital facility	140113	12	17	14.1	Active	O
GPBC02	Physical Security Facility Upgrades & Additions - Capital		22			Active	O
GPCC01	CAPITAL - Relocate SCADA Equipment	13248	13	10.5	5.6	Active	O
GPCC02	Electrical systems and life safety upgrades	13243	26	38	5.5	Active	O
GPOC01	Normal Improvements to Capital Facility	13213	0		0	Closed 2/2014	O
GPOC02	Physical Security Additions	13240	0		0	Closed 11/2014	O
GPOC03	Door Replacements	13242	0		0	Closed 8/2014	O
		Sub-Totals:	73	65.5	25.2		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETE D AMOUNT	AUTH AMOUNT	PROJECTE D AMOUNT	PROJECT STATUS	
	SUBSTATION ELECTRIC						
SPBC01	Broken Ground - Site Evaluation, Permitting, Preliminary Survey	140144	652	11,297.70	898.7	Active	I
SPCC01	Penacook Substation: Replace Control Wiring	13275	39.7	118.3	103.6	Closed 11/2014	O
SPNC01	Replace Failed Cap Bank, RTU and Regulators due to a Fault	140133	0	72.1	87.5	Active	O
SPNC03	Deenergize Bus # 1 at Penacook to replace broken insulator	140155	0		35	Closed 10/2014	O
SPNC05	Transformer 7T1 Replacement at Bow Junction and Purchase Spare Transformer	140161	0	398.7	118.5	Active	O
SPNC06	Purchase SPU for failed Bow Junction Unit	140164	0	14	0	Active	O
SPNC07	Purchase SPU for Failed Bridge Street Collector	140166	0	12	10	Closed 11/2014	O
SPNC09	Replace Faulted 396J2 Switch Lightning Arresters	140180	0	22.8	0	Active	O
SPOC01	Langdon St. Cap and Pin Insulators	13219	0	60.6	10.4	Active	O
SPOC03	Penacook S/S - 036 Load Shed Scheme	13271	0		5.2	Closed 10/2014	O
SPOC04	Install Capacitor Bank	243	0		0	Closed 1/2014	O

Electric Category	2014

Budget Category

CONSTRUCTION BUDGET 2014 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
		Sub-Totals:	691.7	11,996.10	1,268.90		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TRANSPORTATION ELECTRIC						
FEBC01	Replace Vehicle #11		0			Closed 10/2014	O
FEBC02	Replace Vehicle #15		0			Closed 10/2014	O
FEBC03	Replace bucket truck #25		0			Completed 11/2014	O
FEBC04	Replace Flat bed Trailer		0			Closed 10/2014	O
		Sub-Totals:	0	0	0		
		Grand Totals:	5,343.50	17,119.70	7,574.60		

Electric Category	**2014**		**Budget Category**

CONSTRUCTION BUDGET 2014 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	BLANKETS ELECTRIC						
BABE14	Electric T & D	141000	1,594.70	1,581.40	1,522.10	Active	M
BABE15	Electric T&D	151000	0		0	Active	M
BACE14	Electric T&D Improvements	13000	95.4		81.1	Closed 10/2014	M
BAOE11	Electric T&D Improvements	200	0		0	Closed 1/2014	M
BAOE12	Electric T&D Improvements	2000	0		-0.9	Closed 5/2014	M
BAOE13	Electric T&D Improvements	1000	0		0	Closed 5/2014	M
BBBE14	New Customer Additions	141001	377.8	416.1	442.3	Active	C
BBBE15	NewCustomer Additions	151001	0		0	Active	C
BBCE14	New Customer Additions	13001	13		44.1	Closed 10/2014	C
BBOE12	New Customer Additions	2001	0		0	Closed 5/2014	C
BCBE14	Outdoor Lighting	141002	292.8	292.8	230	Active	M
BCBE15	Outdoor Lighting	151002	0		0	Active	M
BCCE13	Outdoor Lighting	2002	0		0	Closed 5/2014	M
BCCE14	Outdoor Lighting	13002	5		4.9	Closed 10/2014	M
BCOE13	Outdoor Lighting	1002	0		0	Closed 5/2014	M
BDBE14	Emergency & Storm	141003	413.6	400.8	434.2	Active	M
BDBE15	Emergency & Storm	151003	0		0	Active	M
BDCE13	Emergency & Storm Restoration	2003	0		0	Closed 5/2014	M
BDCE14	Emergency & Storm	13003	18.2		-2.5	Closed 10/2014	M
BDOE13	Emergency Restoration	1003	0		0	Closed 5/2014	M
BEBE14	Billable Work	141004	404.8	400.1	421	Active	M
BEBE15	Make Ready for Apllication HFA-14-601	151004	0		0	Active	M
BECE13	Billable Work	2004	0		0	Closed 5/2014	M
BECE14	Billable Work	13004	101		21	Closed 10/2014	M
BEOE11	Billables	1004	0		0	Closed 5/2014	M
BFBE14	Transformer Purchase-Company	141005	0		0	Active	I
BFBE15	2015 Transformer Purchases-Company	151005	0		0	Active	I
BFCE14	Transformer Purchases - Company Conversions	13005	4.6		4.7	Closed 7/2014	I
BGBE14	Transformer Purchase-Cust Req-URD	141006	971.7	1,281.20	1,548.60	Active	C
BGBE15	2015 Transformer Purchases-Customer	151006	0		0	Active	C
BGCE14	Transformer Purchase - Customer	13006	31.3		21.5	Closed 7/2014	C
BHBE14	Meter Purchase-Company	141008	153	153	137.8	Active	M
BHBE15	2015 Meter Purchases-Company	151008	0		0	Active	M
BHOE13	Electric Meter Purchases - Company	13008	0		16.4	Closed 4/2014	M
BIBE14	Meter Purchase-Customer	141007	172.1	172.1	191.5	Active	C
BIBE15	2015 Meter Purchases-Customer	151007	0		0	Active	C
BIOE13	Electric Meter Purchases - Customer	13007	0		-16.4	Closed 4/2014	C
		Sub-Totals:	4,649.10	4,697.50	5,101.40		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS ELECTRIC						
ECEE01	AMI - Guinea Switching PLX Permanent	141035	94.6	94.6	87.7	Active	O
ECEE02	Two Way Radio Replacements	141018	5	5	1	Active	O
EECE01	UES Radio Upgrade Seacoast	13143	11		0	Closed 9/2014	O
		Sub-Totals:	110.6	99.6	88.7		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS GENERAL						
ECNE01	Replace AMI SPU and Cell Modem	141034	0	9.3	2	Active	O
ECOE01	Two Way Radio Replacements	13149	0		0	Closed 2/2014	O
ECOE02	AMI Equipment, Unanticipated Replacement	13121	0		0	Closed 2/2014	O
ECOE03	Replace Seabrook Marsh RTU	13193	0	20.4	3.8	Active	O
ECOE05	Purchase Lab Equipment for Line Evaluation	13190	0		0	Closed 5/2014	O
ECOE07	Add AMI Switching Group	2177	0		2.2	Closed 2/2014	O
		Sub-Totals:	0	29.7	8		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	DISTRIBUTION ELECTRIC						
DABE00	Overhead Line Extensions - New Projects		123.3		21.6	Active	C
DABE01	Single Phase, Overhead Line Ext., 5 South Rd, Brentwood	141044	0		14	Closed 8/2014	
DABE02	Single Phase, Overhead Line Ext., 4 Merrimac Rd., Newton	141057	0		8.2	Closed 9/2014	
DABE03	Three Phase, Temporary O/H Line Ext. 21 Chevy Chase Rd., Seabrook	141062	0		-0.6	Closed 12/2014	
DACE00	Overhead Line Extensions, Carryover		34.4		1.2	Active	C
DACE01	Single Phase, O/H Line Ext., 55 Heath St	13171	0		0	Closed 1/2014	
DACE02	Single Phase, O/H Line Ext, 13 Old Town Farm Rd	13176	0		0	Closed 2/2014	
DACE03	Three Phase Service, 22 Exeter Rd., South Hampton	13177	0		0	Closed 10/2014	
DACE04	Single Phase, O/H Line Ext., 71 North Rd, Kingston	13180	0		0.1	Closed 4/2014	
DACE05	Three Phase O/H Line Ext., 4 Plaistow Rd, Plaistow	13185	0		1.1	Closed 2/2014	

Electric Category	2014
Growth	
Customer Additions (C)	2,907,700
Subtotal Growth	2,907,700
Non-Growth	
Reliability (R)	125,400
Maintenance Replacement (M)	3,753,300
Mandated (H)	110,600
System Improvement (I)	4,648,700
Other (O)	409,900
Subtotal Non-Growth	9,047,900
Total	11,955,600
	11,955,600
	0

Budget Category	
Annual Requirements Blankets	**2014**
T&D Improvements	1,602,300
New Customer Additions	486,400
Outdoor Lighting	234,900
Emergency & Storm Restoration	431,700
Billable work	442,000
Transformers	1,574,800
Meters	329,300
Sub-Totals:	**5,101,400**
Distribution	
Overhead Line Extensions over $20,000	22,800
Underground Line Extensions over $20,000	653,300
Street Light Projects	-
Telephone Company Requests	81,800
Highway Projects	28,800
Distribution Pole Replacements	714,000
Specific Projects: Distribution	1,197,600
Sub-Totals:	**2,698,300**
Substation	
Specific Projects: Substation	3,908,400
Sub-Totals:	**3,908,400**
Communications	**96,700**
Tools, Shop, Garage	**110,800**
Laboratory	**7,300**
Office	**2,300**
Structures	**30,400**
Distribution Totals:	**11,955,600**

CONSTRUCTION BUDGET 2014 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DBBE00	Underground Line Extensions - New Projects		223.3		367.5	Active	C
DBBE01	Single Phase, URD Line Ext., 22 Winslow Dr, Atkinson	141014	0		0.2	Closed 10/2014	
DBBE02	Three Phase, URD Line Ext, 580 Winnacunnet Rd, Hampton	141036	0	29.9	33.6	Active	
DBBE03	Three Phase, URD Line Ext., 5-9 Plaistow Rd, Plaistow	141037	0	26.2	31.6	Active	
DBBE04	Single Phase, URD Line Ext, Phase 5 of Sargent Woods	141038	0	43.7	61	Closed 11/2014	
DBBE05	Single Phase, URD Line Ext., Rocks Rd, Seabrook	141040	0		58.4	Closed 11/2014	
DBBE06	Three Phase, URD Line Ext., 600 Lafayette Rd., Seabrook	141042	0	122.9	128	Active	
DBBE07	Three Phase, URD Line Ext., 3 Portsmouth Ave., Stratham	141043	0		9.8	Closed 7/2014	
DBBE08	Three Phase, URD Line Ext., 275 Ocean Blvd., Hampton	141045	0		-6.1	Active	
DBBE09	Three Phase, URD Line Ext., 169 Ocean Blvd., Hampton	141046	0		24.3	Closed 8/2014	
DBBE10	Single Phase, URD Line Ext., off Hillcrest Dr., Plaistow	141048	0	82.9	73	Closed 12/2014	
DBBE11	Three Phase, URD Line Ext., off Kelley Road, Plaistow	141059	0	33.1	5.3	Active	
DBBE12	Single Phase, URD Line Ext., Jean Dr., off Gove Rd., Seabrook	141060	0		-6.6	Active	
DBBE13	Three Phase, URD Line Ext., 100 Ledge Rd., Seabrook	141061	0		10	Active	
DBBE14	Three Phase, URD Line Ext., One Meeting Place, Exeter	141063	0		-30.1	Active	
DBBE15	Three Phase, URD Line Ext., 133 Exeter Rd., Hampton Falls	141064	0	24.5	31.5	Closed 12/2014	
DBBE16	Three Phase, URD Line Ext., 10 Puzzle Ln., Newton	141067	0	13.5	0.3	Active	
DBBE17	Single Phase, URD Line Ext., 22 Cottage Rd., Kensington	141070	0	24.2	-22.7	Active	
DBBE18	Single Phase, URD Line Ext. Sargent Woods, Newton, Phase 6	141072	0	25	-9.5	Active	
DBBE19	Three Phase, URD Line Ext., Sterling Hill, Bldg 7, Exeter	141075	0		-4.3	Active	
DBBE20	Three Phase, URD Line Ext., 7 Puzzle Ln., Newton	141076	0	19.5	-10	Active	
DBBE21	Single Phase, URD Line Ext., 7 State Rt 125, Phase 2	141077	0		-10	Active	
DBCE00	Underground Line Extensions, Carryovers		163.9		285.8	Active	C
DBCE01	Single Phase, URD Line Ext., Bunker Hill Avenue, Stratham	13141	0		0	Closed 10/2014	
DBCE02	Three Phase, URD Line Ext., 700 Lafayette Rd, Seabrook	13151	0	194.2	141.8	Active	
DBCE04	Single Phase, URD Line Ext., 10 Columbus Ave., Exeter	13167	0		-1.1	Closed 4/2014	
DBCE05	Three Phase, URD LIne Ext., Sterling Hill, Exeter - Building 6	13181	0		5.7	Closed 3/2014	
DBCE06	Single Phase, URD Line Ext., Keefe Ave., Hampton	13186	0		1.1	Closed 10/2014	
DBCE07	Single Phase, URD Line Ext., Sargent Woods, Newton - PH 4A	13188	0		23.8	Closed 10/2014	
DBCE08	Three Phase, URD Line Ext., 339 Ocean Blvd., Hampton	13189	0		30.7	Closed 9/2014	
DBCE09	Single Phase, URD Line Ext., Juniper Ln, Hampton	13191	0		42.6	Closed 4/2014	
DBCE10	Single Phase, URD Line Ext., off Rt 125, Kingston	2165	0	122.6	41.3	Completed 11/2014	
DCBE00	Street Light Projects		59.2			Active	M
DCCE00	Street Light Projects, Carryover		0			Active	M
DDBE00	Telephone Company Requests		1,026.80		81.8	Active	H
DDBE01	Replacement and Changeover of Poles, Great Pond Rd.	141030	0		34.2	Closed 7/2014	
DDBE02	3353 Line Relocation, State Rt. 101, Hampton	141047	0	300	47.6	Active	
DDCE00	Telephone Company Requests, Carryover		0			Active	H
DEBE00	Highway Projects		159.5		0	Active	H
DEBE02	Relocation of Highway Light	141079	0		0	Active	
Dec-00	Highway Projects, Carryover		88.7		28.8	Active	H
DECE01	Relocation of Poles, Westside Dr., Atkinson	13162	0		28.8	Closed 12/2014	
DPBE01	Distribution Pole Replacements (REP)	151009	683.5		714	Closed 12/2014	M
DPBE02	Circuit 59X1 - Reconductor Exeter Road	141022	195.6		116.4	Closed 7/2014	I
DPBE03	Cir. 59X1 Install Regulator, Goodwin Rd	141013	48.4		39.4	Closed 8/2014	I
DPBE04	Winnacunnet Road Tap - Install Regulation	141021	386.1	386.1	170.1	Active	I
DPBE05	Reconductor Portions of 2X3, 23X1 and 15X1	151010	0		0	Active	I
DPCE01	Circuit 58X1 - Convert Newton Road to 34.5 kV	13173	215.7		224.4	Closed 7/2014	I
DPCE02	Reconductor 3360 and 3371 Lines - Timber Swamp to Guinea	13155	64.9		319.2	Closed 8/2014	I
DPNE02	Replace Direct Buried Underground Facilities, 32 Industrial Dr., Exeter	141055	0	52.6	47.1	Completed 12/2014	M
DPNE03	Reconductor Fourteen (14) Pole Line Sections Along New Zealand Rd., Seabrook	141073	0	131.5	10	Active	I
DPNE04	Replace Neutral along Country Pond Rd & Concannon Rd., Kingston/Newton	141074	0		115	Completed 12/2014	M
DPOE01	Purchase Regulators for Various Distribution Projects	13116	0		0	Closed 5/2014	I
DPOE02	Circuit 43X1 - Convert Route 111/Kingston Rd., Exeter to 34.5 kV	13114	0		0	Closed 1/2014	I
DPOE03	Circuit 5H1 Transfer to 21W1, Plaistow	13132	0		0	Closed 1/2014	I
DPOE04	Replace the 03341 and the 3352 Reclosers at Wolf Hill	13161	0	154.6	1.3	Active	M
DPOE05	Circuit 19X3 Load Transfer to Circuit 27X2, Court St., Exeter	1059	0		18.5	Closed 11/2014	I
DPOE06	Circuit 51X1 - Convert Portion of High Street, Stratham	13147	0		0	Closed 2/2014	I
DPOE08	Replace and Changeover Pole 141/15	13194	0		0	Closed 1/2014	M
DPOE09	Replace Guinea Rd 47X1 Regs	8046	0		1.7	Closed 7/2014	M
DRBE00	Reliabilty Projects		192.6		125.4	Active	R
DRBE01	Replace Stard Road Recloser	141041	75.9	75.9	67	Completed 12/2014	
DRBE02	3359 Line Remote Fault Indication at Stard Rd Tap		0			Cancelled 9/2014	
DRBE03	Circuit 13W1 - Install Recloser and Sectionalizer	141020	0		16.3	Closed 7/2014	
DRBE07	Installing Cutouts on Various Circuits to Address Unprotected Laterals (REP)	141051	0		34.4	Closed 11/2014	
DRBE08	3341 Line and 3352 Line Remote Fault Indication at Exeter Switching	141066	0	24.5	7.8	Completed 11/2014	
DRCE00	Reliabilty Projects, Carryover		0			Active	R
DROE01	Hampton S/S - Install Protective Devices on 3342, 3353 and 3348	13170	0	645.1	5.2	Active	M
DROE02	Portsmouth Ave S/S - Install Reclosers	13166	0		3.9	Closed 4/2014	M
		Sub-Totals:	3,741.80	2,532.60	2698.3		
BUDGET		AUTH	BUDGETED	AUTH	PROJECTED	PROJECT	

Electric Category	2014		Budget Category

CONSTRUCTION BUDGET 2014 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
NUMBER	DESCRIPTION	NUMBER	AMOUNT	AMOUNT	AMOUNT	STATUS	
	TOOLS, SHOP, GARAGE ELECTRIC						
EAEE01	Normal Additions and Replacements of Tools & Equipment	141016	7	17	12.2	Active	O
EAEE02	Purchase and Replace Rubber Goods	141017	5	5	4.8	Active	O
EAEE03	Purchase and Replace Hot Line Tools	141019	3.5	3.5	3	Active	O
EAEE04	Normal additions & replacement - tools & equipment Meter Department	141024	3	3	2.9	Active	O
EAEE05	Normal Tools Purcahase and Replacement Substation	141028	7	7	7.7	Active	O
EAEE06	Purchase Oil Filtration Unit	141029	57	57	58.6	Closed 12/2014	O
EAEE07	Replacement of Symbol Hand helds	141026	14		13.8	Closed 10/2014	O
EAEE08	Replace the FC200 handheld readers	141027	8.9		7.7	Closed 10/2014	O
		Sub-Totals:	105.4	92.5	110.7		
BUDGET		AUTH	BUDGETED	AUTH	PROJECTED	PROJECT	
NUMBER	DESCRIPTION	NUMBER	AMOUNT	AMOUNT	AMOUNT	STATUS	
	TOOLS, SHOP, GARAGE GENERAL						
EAOE01	Normal Additions and Replacements of Tools & Equipment	13127	0		-0.4	Closed 2/2014	O
EAOE02	Purchase and Replace Rubber Goods	13128	0		0.2	Closed 2/2014	O
EAOE03	Purchase and Replace Hot Line Tools	13129	0		0.3	Closed 2/2014	O
		Sub-Totals:	0	0	0.1		
BUDGET		AUTH	BUDGETED	AUTH	PROJECTED	PROJECT	
NUMBER	DESCRIPTION	NUMBER	AMOUNT	AMOUNT	AMOUNT	STATUS	
	LABORATORY GENERAL						
EBBE01	Lab Equipment - Normal Additions and Replacements	141025	7	7	7.3	Active	O
		Sub-Totals:	7	7	7.3		
BUDGET		AUTH	BUDGETED	AUTH	PROJECTED	PROJECT	
NUMBER	DESCRIPTION	NUMBER	AMOUNT	AMOUNT	AMOUNT	STATUS	
	OFFICE ELECTRIC						
EDEE01	Office Furniture and Equipment	141023	3.5	3.5	2.3	Active	O
		Sub-Totals:	3.5	3.5	2.3		
BUDGET		AUTH	BUDGETED	AUTH	PROJECTED	PROJECT	
NUMBER	DESCRIPTION	NUMBER	AMOUNT	AMOUNT	AMOUNT	STATUS	
	OFFICE GENERAL						
EDOE01	Office Furniture and Equipment	13139	0		0	Closed 2/2014	O
		Sub-Totals:	0	0	0		
BUDGET		AUTH	BUDGETED	AUTH	PROJECTED	PROJECT	
NUMBER	DESCRIPTION	NUMBER	AMOUNT	AMOUNT	AMOUNT	STATUS	
	STRUCTURES GENERAL						
GPBE01	Normal improvements to Seacoast Facility	141015	15	15	10.5	Active	O
GPBE02	Physical Security Facility Upgrades & Additions		28			Active	O
GPCE01	Electric system/life safety upgrades	13146	40	35	2.2	Active	O
GPOE01	Normal Improvements to Kensington Facility	13124	0		0	Closed 2/2014	O
GPOE02	Physical security upgrades	13144	0	68.3	17.7	Closed 12/2014	O
GPOE03	Door Replacements	13145	0		0	Closed 8/2014	O
		Sub-Totals:	83	118.3	30.4		
BUDGET		AUTH	BUDGETED	AUTH	PROJECTED	PROJECT	
NUMBER	DESCRIPTION	NUMBER	AMOUNT	AMOUNT	AMOUNT	STATUS	
	SUBSTATION ELECTRIC						
SPBE02	Guinea 18C2 and 18C3 - Replace Switches and Unground	151011	0		0	Active	O
SPCE01	Kingston Substation-System Supply	13184	4,225.00	12,705.60	3,568.40	Active	I
SPCE02	Replace 3360 and 3371 Breakers at Guinea Sw/S	13148	72.1	345.8	177.6	Closed 12/2014	I
SPNE01	Replace Transformer Oil in 22T1	141058	0	56.2	42.4	Closed 12/2014	O
SPNE02	Replace Failed SPU Unit at 3347 Tap	141065	0	12.5	12.4	Closed 12/2014	O
SPNE03	Replace Dows Hill Recloser and Regulator due to fault.	141068	0		48.5	Completed 11/2014	O
SPNE04	Replace Failed SPU at Timberlane Substation	141069	0	12	10	Closed 12/2014	O
SPNE05	Replace SPU Collector at Guinea Switch on Bus A	141071	0	12	0	Active	O
SPOE01	Westville S/S Add Second Transformer	13125	0		0	Closed 1/2014	O
SPOE02	Exeter Sw/S - Raise Motor Operators	13122	0		0	Closed 7/2014	O
SPOE03	Hampton Beach S/S - Replace 4 kV Transformer	13175	0		49.1	Closed 9/2014	O
		Sub-Totals:	4,297.10	13,144.00	3,908.40		
BUDGET		AUTH	BUDGETED	AUTH	PROJECTED	PROJECT	
NUMBER	DESCRIPTION	NUMBER	AMOUNT	AMOUNT	AMOUNT	STATUS	
	TRANSPORTATION ELECTRIC						
FEBE01	Replace truck #26		0			Closed 10/2014	O

Electric Category	2014		Budget Category

CONSTRUCTION BUDGET 2014 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
FEBE02	Replace truck #30		0			Closed 10/2014	O
		Sub-Totals:	0	0	0		
		Grand Totals:	12,997.50	20,724.70	11,955.60		

Electric Category	2014		Budget Category

CONSTRUCTION BUDGET 2015 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	BLANKETS ELECTRIC						
BABC15	2015 Electric T & D	150100	866.5	1,225.00	1,279.80	Active	M
BABC16	Electric T&D Improvements	160100	0		0	Active	M
BACC15	T & D Improvements	140100	30.2	1,032.70	48.8	Completed 5/2015	M
BBBC15	2015 New Customer Additions	150101	279	475	441.2	Active	M
BBBC16	New Customer Additions	160101	0		0	Active	C
BBCC15	New Customer Additions	140101	27.3	282.7	49.7	Completed 6/2015	C
BCBC01	106 Airport Rd-NewOL's Banks Chevorlete	150172	0		-25.2	Active	C
BCBC15	2015 Outdoor Lighting	150102	101.7	132	133.7	Active	M
BCBC16	Outdoor Lighting	160102	0		0	Active	M
BCCC15	Outdoor Lighting	140102	4.1	97.7	-0.5	Closed 12/2015	M
BDBC15	2015 Emergency & Storm	150103	574.3	574.3	534.6	Active	M
BDBC16	Emergency & Storm Restoration	160103	0		0.8	Active	M
BDCC15	Emergency & Storm	140103	11.7	622.3	8.6	Active	M
BEBC01	195 N Main St Boscawen -install 3 25kVA transf for 3 ph serv	150175	0		0	Active	M
BEBC15	2015 Billable Work	150104	204.8	237.2	345.1	Active	M
BEBC16	Billable Work	160104	0		0	Active	M
BECC15	Billable Work	140104	8.8	191.6	-30.8	Completed 6/2015	M
BFBC15	2015 Transformer Purchases-Company	150105	21.2	20.1	11.6	Active	I
BFBC16	2016 Transformer Purchases-Company	160105	0		0	Active	I
BFOC15	Transformer Purchase-Company	140105	0		15.3	Closed 3/2015	I
BGBC15	2015 Transformer Purchases-Customer	150106	743.3	647.8	590.4	Active	C
BGBC16	2016 Transformer Purchases-Customer	160106	0		0	Active	C
BGCC15	URG TRANSF CUSTOMER PURCHASE	140106	13.6		30.7	Closed 3/2015	C
BHBC15	2015 Meter Purchases-Company	150108	83.5	83.5	79	Active	M
BHBC16	2016 Meter Purchases-Company	160108	0		0	Active	M
BIBC15	2015 Meter Purchases-Customer	150107	146	146	149.8	Active	C
BIBC16	2016 Meter Purchases-Customer	160107	0		0	Active	C
BICC15	Meter Purchase-Customer	140107	0		0	Completed 1/2015	C
		Sub-Totals:	3,116.00	5,768.00	3,662.60		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS ELECTRIC						
ECEC01	Two Way Radio Replacements	150114	4	4	2.8	Active	O
ECEC02	AMI Equipment, Unanticipated Replacements	150120	10.1	10.1	41	Active	O
ECEC03	Replace and Upgrade Electric SCADA Master	150133	147.9		100.8	Active	O
		Sub-Totals:	162.1	14.1	144.6		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS GENERAL						
ECNC01	2015 Infrastructure	150127	0	200.3	39.9	Active	O
ECNC02	Electric Inspections	150128	0	52	32.9	Active	O
ECNC03	GIS Version Upgrade & Data Model Consolidation	150129	0	94.4	7	Active	O
ECNC04	Municipal Maps and Reports	150134	0	30.6	31.7	Active	O
ECNC05	Milsoft IVR Upgrade	150135	0	10.9	1.8	Closed 12/2015	O
ECNC06	Enhancements for Third Party Attachments-ODI Plant Records	150136	0	17	0	Active	O
ECNC07	MV90xi Upgrade From v2.0 SP1 to v5.0	150137	0	31.2	24	Active	O
ECNC08	CIS, MDMS and Interfaces Internal Control - 2015	150139	0	231	0	Active	O
ECNC09	General Software Enhancements	150143	0	9.9	10.7	Active	O
ECNC10	EETS Enhancements 2015	150169	0	82.8	8.6	Active	O
ECNC11	2015 Cyber Security Enhancements	150170	0	17.2	0	Active	O
ECOC01	Two Way Radio Replacements	140114	0		0	Closed 2/2015	O
ECOC02	2014 INFRASTRUCTURE	140126	0		1.5	Closed 3/2015	O
ECOC03	2014 AMI/SCADA Cyber Project	140128	0	42.8	1	Closed 12/2015	O
ECOC04	AMI Version Update and PLX Functionality	140129	0	27	-0.2	Closed 12/2015	O
ECOC05	OMS Web Map Improvements	140130	0		0	Closed 2/2015	O
ECOC06	Desktop Client Management	140131	0	22.6	2.4	Closed 3/2015	O
ECOC07	Upgrade Generator Interconnection Database	140141	0	19.6	-16.2	Active	O
ECOC09	24 Hour Damage Assessment/Field Restoration	140146	0	60.1	36.6	Active	O
ECOC10	General Software Enhancements	140152	0	17.5	0	Closed 3/2015	O
ECOC11	Vehicle GIS/Garmin Overlay	140177	0	12.7	0.3	Active	O
ECOC12	Enhancemements to Critical Financial Control Systems	140178	0		4.6	Closed 3/2015	O
ECOC13	EETS Enhancements	140179	0		2.2	Closed 3/2015	O
ECOC99	Electric Inspections	140145	0		2.4	Closed 10/2015	O
		Sub-Totals:	0	979.7	191.2		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	DISTRIBUTION ELECTRIC						
DABC00	Overhead Line Extensions		66.4		-2	Active	C

Electric Category	2015
Growth	
Customer Additions (C)	880,200
Subtotal Growth	880,200
Non-Growth	
Reliability (R)	69,000
Maintenance Replacement (M)	4,036,800
Mandated (H)	15,300
System Improvement (I)	2,525,100
Other (O)	934,800
Subtotal Non-Growth	7,581,000
Total	8,461,200
	8,461,200
	0

Budget Category	
Annual Requirements Blankets	**2015**
T&D Improvements	1,328,600
New Customer Additions	490,900
Outdoor Lighting	108,000
Emergency & Storm Restoration	544,000
Billable work	314,300
Transformers	648,000
Meters	228,800
Sub-Totals:	**3,662,600**
Distribution	
Overhead Line Extensions over $20,000	30,100
Underground Line Extensions over $20,000	54,700
Street Light Projects	-
Telephone Company Requests	-
Highway Projects	15,300
Distribution Pole Replacements	674,100
Specific Projects: Distribution	591,400
Sub-Totals:	**1,365,600**
Substation	
Specific Projects: Substation	2,976,700
Sub-Totals:	**2,976,700**
Communications	**335,800**
Tools, Shop, Garage	**52,800**
Laboratory	**48,400**
Office	**600**
Structures	**18,700**
Distribution Totals:	**8,461,200**

CONSTRUCTION BUDGET 2015 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DABC02	250 Pleasant St-Concord Hospital-relocate pole	150162	0		-2	Active	
DACC00	Overhead Line Extensions - Carryover		8.1		32.1	Completed 9/2015	C
DACC01	158 Canterbury Rd Chichester-OH & URD Line Ext-Billable	140160	0	14.7	-0.5	Closed 12/2015	
DACC03	170 South Rd Salisbury, Four Pole OH Line Extension-Billable	140174	0	9.9	31.3	Closed 12/2015	
DACC04	34 Boyce Rd Canterbury, OH to URD Line Extension-Billable	140175	0		1.4	Closed 4/2015	
DBBC00	Underground Line Extensions		108.7		59.6	Active	C
DBBC01	Stonesled Farms Ph 2 Lewis Ln Bow-urd line ext	150150	0	33.6	28.6	Active	
DBBC02	273 Old Loudon Rd 3 ph primary urd line ext	150151	0	18	24.5	Active	
DBBC03	Triangle Park Dr 3 ph primary urd line ext	150152	0	31.7	20.6	Active	
DBBC04	4 Thibeault Dr Bow3 ph line primary urd line ext	150153	0	52.6	19.1	Active	
DBBC05	12 Cross St Penacook Sing Ph Urd Line Ext-Billable	150154	0	13	-3.6	Active	
DBBC06	The Woods of BowDev-Parson's Way Ph2 urd line ext	150155	0	13	-5.3	Active	
DBBC07	115 Appleton St Concord-OH to Urd-Billable	150158	0	3.9	-2.3	Active	
DBBC08	121 Water St-OH to Urd-Non-billable	150164	0	5	0	Cancelled 11/2015	
DBBC09	121 Water St Boscawen-OH to Urd-Billable	150163	0	5	-27.8	Active	
DBBC10	121 Water ST Boscawe-OH to Urd Billable	150167	0	46.4	11.9	Cancelled 10/2015	
DBBC11	34 Reserve Pl-Sing Ph Urd Line Ext	150174	0	5.4	-5.9	Active	
DBCC00	Underground Line Extensions, Carryover		13.6		-4.9	Completed 9/2015	C
DBCC01	341 Mountain Rd Concord-Primary Underground Line Ext	140137	0		6.2	Closed 1/2015	
DBCC02	69 Dover Rd -3 ph upgrade	140151	0		1.4	Completed 1/2015	
DBCC04	Nickerson Dr-Oxbow Bluff Sub Divi Ph 2B Line Extension	140181	0	15	24.9	Closed 9/2015	
DBCC06	replacing old primary urd with new	13276	0		-37.4	Closed 3/2015	
DBCC11	3ph line ext to a 500KVA pad for service upgrade	13288	0		0	Completed 1/2015	
DCBC00	Street Light Projects		8.5			Active	M
DCCC00	Street Light Projects - Carryover		0.6			Completed 3/2015	M
DDBC00	Telephone Company Requests		33.8			Active	H
DDCC00	Telephone Company Request - Carryover		3.4			Completed 2/2015	H
DEBC00	Highway Projects		106.5		63.8	Active	H
DEBC01	CIP 35 Phase 6 Road Reconstruction - Village St., Penacook	150140	0	53.7	59.7	Closed 12/2015	
DEBC02	Relocate Luminaires for Road Widening - Route 106, Loudon	150144	0		-0.3	Closed 12/2015	
DEBC03	Install Push Brace, Relocate Quad, Remove Pole 18-1A	150160	0		4.4	Active	
DEBC04	Relocate Pole 70 for Hospital Entrance Widening - Pleasant St., Concord	150161	0		0	Active	
DEBC05	Sewalls Falls Bridge-Relocate Pole Line	150173	0		0	Active	
DECC00	Highway Projects, Carryover		6.2		-48.5	Active	H
DECC02	Pole Relocation for Bridge Replacement - State of NH	140168	0		1.3	Active	
DECC03	CIP 35 - Corridor Improvements - Village St., Penacook	13237	0		0.4	Closed 1/2015	
DECC04	Reroute Overhead Main Line 4X1 Around Village of Penacook	13273	0		-11.4	Closed 2/2015	
DECC05	Relocation of Aluminum Light Standards and Removal of Hi Mast	2254	0		-38.7	Active	
DPBC01	Distribution Pole Replacements	150126	603.9	694.2	674.1	Closed 12/2015	M
DPBC02	Install Regulator C37X1 - Hannah Dustin Dr., Concord	150142	47.6	47.6	40	Closed 12/2015	M
DPBC03	Relocate 396X1 tap	150148	167	51.5	132.6	Active	M
DPNC01	Replace Failed Pri UG - Pads 2-3 - Broken Ground Dr., Concord	150131	0	76.4	0	Completed 10/2015	M
DPNC03	November 26 Snow Storm	140183	0		349.8	Closed 5/2015	M
DPOC02	374 Line Tie to 318 Line - Garvins 115kV Project	140169	0		0	Closed 10/2015	M
DPOC03	Install New Underground Switch, 211P, MH25	13218	0	51.6	0	Completed 2/2015	M
DRBC00	Install Fusesaver device on pole # 130 Bow Bog Rd and P# 28 New Orchard Rd. Epsom	150157	267.9		68.9	Active	R
DRBC07	Reliability Improvements on 34.5 KV main lines and Sub Trans lines	150168	0	91.8	68.9	Active	
DRCC00	Reliabilty Projects, Carryover		0			Completed 2/2015	R
DROC01	33 Line Remote Fault Indication at Pleasant Street	140148	0	24.5	0.1	Closed 12/2015	R
		Sub-Totals:	1,442.60	1,358.60	1365.6		

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	TOOLS, SHOP, GARAGE ELECTRIC						
EAEC01	Electric Tools, Shop & Garage normal replacements	150115	13.5	13.5	18.2	Active	O
EAEC02	Purchase and replace Rubber Goods	150122	5	5	3	Closed 12/2015	O
EAEC03	Purchase and Replace Hot Line Tools	150123	4	4	3.4	Active	O
EAEC04	Normal additions & replacement - tools & equipment Metering	150110	7	7	8.2	Active	O
EAEC05	Normal Replacement and Additions Substation Tools	150119	7	7	7.3	Active	O
EAEC06	Purchase Bierer ST800 Service Tester	150124	2.4	2.4	2.7	Completed 4/2015	O
EEOC01	NH ESCC RTU Replacement	13293	0	42	0	Active	O
		Sub-Totals:	38.9	81	42.8		

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	TOOLS, SHOP, GARAGE GENERAL						
EAOC01	Purchase tools for new bucket truck # 25	140176	0	5	0	Closed 12/2015	O
EAOC02	Tools, Shop & Garage - Normal Additions and Replacements	140122	0	21	7.2	Closed 12/2015	O
EAOC03	Purchase and Replace Rubber Goods	140123	0	5	2.2	Completed 2/2015	O
EAOC04	Purchase and Replace Hot Line Tools	140124	0		0.6	Closed 2/2015	O
		Sub-Totals:	0	31	10		

Electric Category	2015		Budget Category

CONSTRUCTION BUDGET 2015 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	LABORATORY GENERAL						
EBBC01	Lab Equipment - Normal Additions and Replacements	150111	7	7	6.6	Active	O
EBBC02	Purchase Meter Shop Test Station	150112	38	38	39.4	Closed 12/2015	O
EBOC01	Lab Equipment - Normal Additions and Replacements	140120	0		2.4	Closed 2/2015	O
		Sub-Totals:	45	45	48.4		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE ELECTRIC						
EDEC01	Office Furniture and Equipment	150125	6	6	0.6	Active	O
		Sub-Totals:	6	6	0.6		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE GENERAL						
EDOC01	Office Furniture & Equipment-Normal Additions and Replacements	140116	0		0	Closed 2/2015	O
		Sub-Totals:	0	0	0		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	STRUCTURES GENERAL						
GPBC01	Normal Improvements to Capital Facility	150113	15	15	18.7	Active	O
GPCC01	CAPITAL - Relocate SCADA Equipment	13248	13	20.6	0	Active	O
GPCC02	Electrical systems and life safety upgrades	13243	32	46.3	0	Active	O
GPOC01	Nomal Improvemnts to Capital facility	140113	0		0	Closed 2/2015	O
		Sub-Totals:	60	81.9	18.7		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	SUBSTATION ELECTRIC						
SPBC01	West Concord 2H1 & 2H2 - Eliminate AC Tripping	150138	23.2	23.2	0	Active	O
SPBC02	Purchase- Maintenance Reporting Database for Substations	150130	31.2	31.2	22.3	Completed 11/2015	O
SPBC03	Crushed Stone in Substations	150121	23.6	23.6	7.3	Completed 11/2015	O
SPBC04	Replace Bridge Street Transfer Trip - PSNH Garvins Rebuild		77.5			Active	O
SPCC01	Broken Ground - Site Evaluation, Permitting, Preliminary Survey	140144	1,300.00	11,297.70	2,498.20	Active	I
SPCC02	Transformer 7T1 Replacement at Bow Junction and Purchase Spare Transformer	140161	372.3	518.7	332.1	Active	O
SPNC02	Replace Regulator on 1H3 Phase B	150146	0	25.2	13	Active	O
SPNC03	Replace Regulator on 3H2 Phase B	150147	0	26.2	11.6	Active	O
SPNC04	Replace Failed Recloser at Substation	150149	0	36.2	17.4	Active	O
SPNC05	Replace Failed Motor Operator on the 374J4 Switch	150156	0	17.8	0	Active	O
SPNC06	Replace Failed 1H1 and 2H2 Regulators	150166	0	46.4	0	Active	O
SPNC07	Replace Failed Regulator on Dover Rd Chichester	150171	0	40.2	0	Active	O
SPNC10	SPU 3000 Failures during Snowstorm	140184	0	30	10.1	Completed 5/2015	O
SPOC02	Replace Failed Cap Bank, RTU and Regulators due to a Fault	140133	0	123.5	35.4	Active	O
SPOC03	Purchase SPU for failed Bow Junction Unit	140164	0	14	10	Completed 2/2015	O
SPOC04	Purchase SPU for Failed Bridge Street Collector	140166	0		0	Closed 1/2015	O
SPOC05	Replace Faulted 396J2 Switch Lightning Arresters	140180	0	22.8	0	Completed 1/2015	O
SPOC06	Langdon St. Cap and Pin Insulators	13219	0		19.3	Closed 4/2015	O
		Sub-Totals:	1,827.70	12,276.50	2,976.70		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TRANSPORTATION ELECTRIC						
FEBC01	Replace pickup #54		0			Completed 6/2015	O
FEBC02	Replace Electric Manager pickup #14		0			Completed 4/2015	O
FEBC03	Replace plow/stockroom vehicle #52		0			Completed 5/2015	O
		Sub-Totals:	0	0	0		
		Grand Totals:	6,698.40	20,641.80	8,461.20		

Electric Category	2015

Budget Category

CONSTRUCTION BUDGET 2015 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	BLANKETS ELECTRIC						
BABE15	2015 Electric T&D	151000	1,558.50	1,507.20	1,220.90	Active	M
BABE16	Electric T&D Improvements	161000	0		1.2	Active	M
BACE15	Electric T & D	141000	94.3	1,581.40	39.3	Closed 12/2015	M
BBBE15	2015 New Customer Additions	151001	469.9	469.6	541.6	Active	C
BBBE16	New Customer Additons	161001	0		0	Active	C
BBCE15	New Customer Additions	141001	17.5	416.1	8.6	Active	C
BCBE15	2015 Outdoor Lighting	151002	136.7	162.7	212.5	Active	M
BCBE16	Outdoor Lighting	161002	0		0.2	Active	M
BCCE15	Outdoor Lighting	141002	5.2	292.8	8.5	Closed 12/2015	M
BDBE15	2015 Emergency & Storm	151003	454.1	484.5	456.8	Active	M
BDBE16	Billable Work	161004	0		0	Active	M
BDCE15	Emergency & Storm	141003	15.7	400.8	-51.1	Active	M
BEBE15	2015 Billable Work	151004	455.6	390.1	311.3	Active	M
BECE15	Billable Work	141004	24.7	400.1	-104.3	Active	M
BFBE15	2015 Transformer Purchases-Company	151005	55.5	201.1	185.2	Active	I
BFBE16	2016 Transformer Purchases-Company	161005	0		0	Active	I
BFCE15	Transformer Purchase-Company	141005	0		0	Active	I
BGBE15	2015 Transformer Purchases-Customer	151006	1,171.80	1,171.30	1,177.20	Active	C
BGBE16	2016 Transformer Purchases-Customer	161006	0		0	Active	C
BGCE15	Transformer Purchase-Cust Req-URD	141006	29.7		51.4	Active	C
BHBE15	2015 Meter Purchases-Company	151008	151.8	151.8	141.7	Active	M
BHBE16	2016 Meter Purchases-Company	161008	0		0	Active	M
BHCE15	Meter Purchase-Company	141008	0		0.3	Completed 1/2015	C
BIBE15	2015 Meter Purchases-Customer	151007	178.4	178.4	208.3	Completed 12/2015	C
BIBE16	2016 Meter Purchases-Customer	161007	0		0	Active	C
		Sub-Totals:	4,819.60	7,807.90	4,409.60		

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	COMMUNICATIONS ELECTRIC						
ECEE01	AMI Equipment, Normal Replacements	151037	10.3	12.8	23.2	Active	O
ECEE02	Two Way Radio Replacements	151018	3	3	0	Active	O
ECEE03	Replace and Upgrade Electric SCADA Master		147.9			Cancelled 3/2015	O
EECE01	Replace Seabrook Marsh RTU	13193	31	20.4	0	Active	O
		Sub-Totals:	192.3	36.1	23.2		

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	COMMUNICATIONS GENERAL						
ECOE01	AMI - Guinea Switching PLX Permanent	141035	0	94.6	1.3	Completed 11/2015	O
ECOE02	Two Way Radio Replacements	141018	0		0	Closed 3/2015	O
ECOE04	Replace AMI SPU and Cell Modem	141034	0	9.3	0	Completed 11/2015	O
		Sub-Totals:	0	103.9	1.3		

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	DISTRIBUTION ELECTRIC						
DABE00	Overhead Line Extensions - New Projects		93.6		33.5	Active	C
DABE01	Single Phase, Overhead Line Ext., Hunt Rd., Kingston	151034	0		24	Closed 10/2015	
DABE02	Three Phase, O/H Line Ext., 31-33 Ocean Blvd., Hampton	151053	0	22.1	17.9	Closed 8/2015	
DABE03	Single Phase, Overhead Line Ext., 218 Haverhill Rd, East Kingston	151099	0	8.5	-8.4	Active	
DACE00	Overhead Line Extensions, Carryover		17.7		0	Active	C
DBBE00	Underground Line Extensions - New Projects		272.2		456.9	Active	C
DBBE01	Single Phase, URD Line Ext., 376 Winnacunnet Rd.	151033	0		39.7	Closed 8/2015	
DBBE02	Three Phase, URD Line Ext., 27 Chestnut St.	151044	0	44.1	-12.7	Active	
DBBE03	Three Phase, URD Line Ext., Mill Rd., Kingston	151048	0	5.3	54.7	Active	
DBBE04	Upgrade Three Phase Service, 44 Greenough Rd.	151051	0		2.1	Closed 10/2015	
DBBE05	Three Phase, URD Line Ext., 56 Linden St., Exeter	151052	0		33.1	Closed 8/2015	
DBBE06	Three Phase, URD Line Ext., 712 Lafayette Rd., Seabrook	151054	0	8.2	11.5	Closed 12/2015	
DBBE07	Three Phase, URD Line Ext., 14-26 N St., Hampton	151055	0	58.8	85	Active	
DBBE08	Single Phase, URD Line Ext., 22 Marshall Rd., Kingston	151057	0	87.7	54.9	Active	
DBBE09	Single Phase, URD Line Ext., 382 Exeter Rd., Hampton	151059	0		13.2	Closed 10/2015	
DBBE10	Three Phase, URD Line Ext., 128 Ashworth Ave., Hampton	151062	0	53.7	44	Closed 12/2015	
DBBE11	Single Phase, URD LIne Ext., 2 Hampton Rd., Exeter	151063	0	76	18.8	Active	
DBBE12	Single Phase, URD Line Ext., 94 Black Snake Rd., Seabrook	151068	0	30	1.8	Active	
DBBE13	Three Phase, URD Line Ext., 172 Main St., Atkinson, Phase 1	151069	0	69.8	92	Active	
DBBE14	Single Phase, URD Line Ext., off Hall Place, Exeter - Charron Circle	151070	0	28.5	25.1	Closed 12/2015	

Electric Category	2015
Growth	
Customer Additions (C)	2,732,100
Subtotal Growth	2,732,100
Non-Growth	
Reliability (R)	539,900
Maintenance Replacement (M)	3,270,600
Mandated (H)	999,300
System Improvement (I)	7,070,600
Other (O)	332,100
Subtotal Non-Growth	12,212,500
Total	14,944,600
	14,944,600
	0

Budget Category	
Annual Requirements Blankets	**2015**
T&D Improvements	1,261,400
New Customer Additions	550,200
Outdoor Lighting	221,200
Emergency & Storm Restoration	405,700
Billable work	207,000
Transformers	1,413,800
Meters	350,300
Sub-Totals:	**4,409,600**
Distribution	
Overhead Line Extensions over $20,000	33,500
Underground Line Extensions over $20,000	711,200
Street Light Projects	3,500
Telephone Company Requests	1,003,100
Highway Projects	(3,800)
Distribution Pole Replacements	635,900
Specific Projects: Distribution	2,249,700
Sub-Totals:	**4,633,100**
Substation	
Specific Projects: Substation	5,797,900
Sub-Totals:	**5,797,900**
Communications	**24,500**
Tools, Shop, Garage	**58,400**
Laboratory	**6,800**
Office	**100**
Structures	**14,200**
Distribution Totals:	**14,944,600**

CONSTRUCTION BUDGET 2015 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DBBE15	Relocate Three Phase Primary Underground, 7 Alumni Dr, Exeter	151077	0		1.6	Closed 10/2015	
DBBE16	Single Phase, URD Line Ext., 86 Woodland Rd., Hampton	151078	0	26.9	-10.3	Active	
DBBE17	Single Phase, URD Line Ext., off Hillcrest Ave., Plaistow - Snow's Brook, PH 2	151082	0	7.7	8.3	Closed 12/2015	
DBBE18	Three Phase, URD Line Ext., 15 Industrial Way, Atkinson	151085	0	22.1	4.6	Active	
DBBE19	Three Phase, URD Line Ext., London Ln, Seabrook	151086	0	11.3	7.5	Closed 12/2015	
DBBE20	Three Phase, URD Line Ext., 377 Ocean Blvd, Hampton	151087	0	35.8	40.9	Active	
DBBE21	Single Phase, URD Line Ext., off Patriots Rd., Strahtam	151088	0	30.1	8.7	Active	
DBBE22	Single Phase, URD Line Ext., off Smith Corner Rd., Plaistow	151089	0	37.9	22.6	Active	
DBBE23	Three Phase, URD Line Ext, Sterling Hill, Exeter - Building 8	151090	0	7	-9.8	Active	
DBBE24	Single Phase, URD Line Ext., Wild Pasture Rd., Kensington	151091	0	19.9	-2.4	Active	
DBBE25	Three Phase, URD Line Ext., 146 Main St., Plaistow	151092	0		-63.6	Active	
DBBE26	Single Phase, URD Line Ext., off North Main St., Newton	151093	0	31.1	-1.3	Active	
DBBE27	Single Phase, URD Line Ext., 109 High St., Stratham	151094	0	32.4	-8.6	Active	
DBBE28	Single Phase, URD Line Ext., 372 Exeter Rd., Hampton	151096	0	11.5	0.1	Active	
DBBE29	Single Phase, URD Line Ext., off Sweet Hill Rd., Plaistow	151098	0		-4.9	Active	
DBCE00	Underground Line Extensions, Carryovers		206.1		254.3	Active	C
DBCE01	Three Phase, URD Line Ext, 580 Winnacunnet Rd, Hampton	141036	0	46.9	5.4	Closed 10/2015	
DBCE02	Three Phase, URD Line Ext., 5-9 Plaistow Rd, Plaistow	141037	0	26.2	-1.2	Closed 2/2015	
DBCE03	Single Phase, URD Line Ext, Phase 5 of Sargent Woods	141038	0		0	Completed 10/2015	
DBCE04	Three Phase, URD Line Ext., 600 Lafayette Rd., Seabrook	141042	0	122.9	-3.9	Completed 8/2015	
DBCE05	Three Phase, URD Line Ext., 275 Ocean Blvd., Hampton	141045	0		30.1	Closed 3/2015	
DBCE06	Single Phase, URD Line Ext., off Hillcrest Dr., Plaistow	141048	0		0	Active	
DBCE07	Three Phase, URD Line Ext., off Kelley Road, Plaistow	141059	0		11.3	Closed 7/2015	
DBCE08	Single Phase, URD Line Ext., Jean Dr., off Gove Rd., Seabrook	141060	0	18.1	18.4	Closed 7/2015	
DBCE09	Three Phase, URD Line Ext., 100 Ledge Rd., Seabrook	141061	0		11.7	Closed 7/2015	
DBCE10	Three Phase, URD Line Ext., One Meeting Place, Exeter	141063	0		52.2	Closed 7/2015	
DBCE12	Three Phase, URD Line Ext., 10 Puzzle Ln., Newton	141067	0		6	Closed 3/2015	
DBCE13	Single Phase, URD Line Ext., 22 Cottage Rd., Kensington	141070	0	24.2	44.6	Closed 12/2015	
DBCE14	Single Phase, URD Line Ext. Sargent Woods, Newton, Phase 6	141072	0		21	Closed 3/2015	
DBCE15	Three Phase, URD Line Ext., Sterling Hill, Bldg 7, Exeter	141075	0	3.6	7.7	Closed 12/2015	
DBCE16	Three Phase, URD Line Ext., 7 Puzzle Ln., Newton	141076	0	19.5	17	Active	
DBCE17	Single Phase, URD Line Ext., 7 State Rt 125, Phase 2	141077	0		39.9	Closed 10/2015	
DBCE18	Three Phase, URD Line Ext., 700 Lafayette Rd, Seabrook	13151	0	194.2	5.2	Closed 12/2015	
DBCE19	Single Phase, URD Line Ext., off Rt 125, Kingston	2165	0		-11.3	Closed 2/2015	
DCBE00	Street Light Projects		44.6		3.5	Active	M
DCBE01	Installation of Street Lighting, Provident Way, Lafayette Rd, Seabrook	151060	0		0.1	Closed 12/2015	
DCBE02	Installation of Street Lighting, Beckman Woods, Seabrook	151079	0	3.1	3.4	Closed 12/2015	
DCBE03	Installation of URD Secondary & Street Light, State Rt 125, Plaistow - 10044G	151084	0	0.6	0	Active	
DCCE00	Street Light Projects, Carryover		0			Active	M
DDBE00	Telephone Company Requests		0		0	Active	H
DDCE00	Telephone Requests, Carryover		876.2		1,003.10	Active	H
DDCE01	3353 Line Relocation, State Rt. 101, Hampton	141047	0	1,080.00	1,003.10	Active	
DEBE00	Highway Projects		124.3		-2.1	Active	H
DEBE03	Relocation of Poles, Lafayette Rd., Seabrook	151081	0		-2.1	Active	
Dec-00	Highway Projects, Carryover		0		-1.7	Active	H
DECE01	Relocation of Highway Light	141079	0		-1.7	Active	
DPBE01	Distribution Pole Replacements (REP)	151009	635.3	635.3	635.9	Closed 12/2015	M
DPBE02	Upgrade Stard Road Tap	151066	341.7	230	151.6	Active	M
DPBE03	Rebuild Country Pond Road to Three-Phase	151035	363.7	363.7	274.2	Closed 9/2015	I
DPBE04	Reconductor Portsmouth Ave, Seabrook Beach	151030	215.8	310	306.1	Closed 9/2015	I
DPBE05	Reconductor Portions of 2X3, 23X1 and 15X1	151010	399.5	399.5	210.9	Closed 6/2015	I
DPCE01	Winnacunnet Road Tap - Install Regulation	141021	245.1	386.1	0	Active	I
DPCE02	Replace the 03341 and the 3352 Reclosers at Wolf Hill	13161	64.4	154.6	43.1	Active	M
DPNE01	Convert Marshall Road, Kingston to 7.97 kV	151036	0	116.8	76.1	Closed 7/2015	I
DPNE02	Convert Ashworth Ave to 8 kV, Circuit 3W4	151041	0	170	119.9	Active	I
DPNE05	Relocate Green Hill Road Stepdowns and Conversion , Exeter	151065	0	70	59.8	Closed 12/2015	I
DPNE06	Replace Three Phase Failed Primary Underground Cable, Chase's Way, Seabrook	151071	0	50.9	51	Completed 9/2015	M
DPNE07	Rebuild and Convert Maple Ave and Main Street, Plaistow - Circuits 5H1/5X3 (new)	151072	0	376.2	156.7	Active	I
DPNE08	Replace Three Phase Failed Primary Underground Cable, 340 Lafayette Rd, Hampton	151073	0	55	54.8	Closed 12/2015	M
DPNE09	Improve Voltage along Wentworth Street, Exeter	151074	0	75	53.6	Completed 9/2015	M
DPNE11	Reconstruct Overhead Pole Line, Highland Ave., Hampton	151097	0	85	16	Active	M
DPNE25	SnowStorm - November 26	141081	0		24.1	Completed 10/2015	M
DPOE01	Distribution Pole Replacement	141010	0		0	Completed 1/2015	M

Electric Category	2015

Budget Category

CONSTRUCTION BUDGET 2015 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DPOE02	Replace Direct Buried Underground Facilities, 32 Industrial Dr., Exeter	141055	0	52.6	0	Completed 1/2015	M
DPOE03	Reconductor Fourteen (14) Pole Line Sections Along New Zealand Rd., Seabrook	141073	0	131.5	111.9	Closed 2/2015	I
DRBE00	Reliability Projects		502.9		530.9	Active	R
DRBE04	New Boston Road Tap - Install Reclosers	151043	0	302	214.6	Active	
DRBE05	Replace manually operated switches with automated switches, 3343 and 3354 Lines	151056	0	285	174.1	Active	
DRBE07	Install Motor Operated Air Breaks on 3362 & 3351 lines, RTU and SCADA	151058	0	150	142.3	Active	
DRCE00	Hampton S/S - Install Breakers 3342, 3353 and 3348 Lines		59.7		9	Active	R
DRCE01	Hampton S/S - Install Protective Devices on 3342, 3353 and 3348	13170	0	645.1	9	Active	
DROE02	3341 Line and 3352 Line Remote Fault Indication at Exeter Switching	141066	0	24.5	0	Closed 3/2015	R
		Sub-Totals:	4,462.90	7,374.90	4633.1		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE ELECTRIC						
EAEE01	Tools, Shop & Garage - Normal Additions and Replacements	151023	13.5	13.5	14	Active	O
EAEE02	Purchase and Replace Rubber Goods	151024	5	5	4.4	Active	O
EAEE03	Purchase and Replace Hot Line Tools	151025	3.5	3.5	3.6	Active	O
EAEE04	Normal additions & replacement - tools & equipment Metering	151012	7	7	8.2	Active	O
EAEE05	Normal Additional Substation Tools	151026	7	7	6.4	Active	O
EAEE06	Purchase/Replace Tooling for New Bucket Truck #8	151031	7	7	8.6	Active	O
EAEE07	Purchase/Replace Tooling for New Digger Truck #17	151032	3.5	3.5	0.4	Active	O
		Sub-Totals:	46.5	46.5	45.6		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE GENERAL						
EAOE01	Normal Additions and Replacements of Tools & Equipment	141016	0	17	8.6	Closed 9/2015	O
EAOE02	Purchase and Replace Rubber Goods	141017	0		1.5	Closed 2/2015	O
EAOE03	Purchase and Replace Hot Line Tools	141019	0		0	Closed 2/2015	O
EAOE04	Normal additions & replacement - tools & equipment Meter Department	141024	0		0.9	Closed 2/2015	O
EAOE05	Normal Tools Purcahase and Replacement Substation	141028	0		0	Closed 2/2015	O
EAOE06	Purchase Oil Filtration Unit	141029	0		1.8	Closed 1/2015	O
		Sub-Totals:	0	17	12.8		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	LABORATORY GENERAL						
EBBE01	Lab Equipment - Normal Additions and Replacements	151013	7	7	6.6	Active	O
EBOE01	Lab Equipment - Normal Additions and Replacements	141025	0		0.2	Closed 2/2015	O
		Sub-Totals:	7	7	6.8		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE ELECTRIC						
EDEE01	Office Furniture and Equipment	151021	6	6	0.1	Active	O
		Sub-Totals:	6	6	0.1		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE GENERAL						
EDOE01	Office Furniture and Equipment	141023	0		0	Closed 2/2015	O
		Sub-Totals:	0	0	0		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	STRUCTURES GENERAL						
GPBE01	Normal Improvements to Seacoast Facility	151016	15	15	12.6	Active	O
GPBE02	Physical Security Facility Upgrades & Additions	151019	35	35	0	Active	O
GPCE01	Electric system/life safety upgrades	13146	40	51.6	1.6	Active	O
GPOE01	Normal improvements to Seacoast Facility	141015	0		0	Closed 3/2015	O
		Sub-Totals:	90	101.6	14.2		

Electric Category	2015		Budget Category

CONSTRUCTION BUDGET 2015 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	SUBSTATION ELECTRIC						
SPBE01	Crushed Stone in Substations	151027	24.5	24.5	13.2	Active	O
SPBE02	Guinea 18C2 and 18C3 - Replace Switches and Unground	151011	141.8	188.8	87.4	Active	O
SPCE01	Kingston Substation-System Supply	13184	5,135.00	12,705.60	5,569.80	Active	I
SPNE01	Replace Gasket on 13.8KV Low Side Bushing	151015	0		31.3	Closed 3/2015	O
SPNE02	Replace Regulator on 7X2 Phase C	151067	0	33.6	16	Active	O
SPNE03	Build New 5X3 Distribution Circuit Position in Plaistow Substation	151076	0	556.1	60.1	Active	O
SPOE01	Replace 3360 and 3371 Breakers at Guinea Sw/S	13148	0		0	Closed 1/2015	O
SPOE02	Replace Transformer Oil in 22T1	141058	0		0	Closed 1/2015	O
SPOE03	Replace Failed SPU Unit at 3347 Tap	141065	0		0	Closed 1/2015	O
SPOE04	Replace Failed SPU at Timberlane Substation	141069	0		0	Closed 1/2015	O
SPOE05	Replace SPU Collector at Guinea Switch on Bus A	141071	0		10	Closed 3/2015	O
SPOE06	SPU 3000 Failure at Seabrook Substation	141080	0		10.1	Closed 3/2015	O
		Sub-Totals:	5,301.30	13,508.50	5,797.90		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TRANSPORTATION ELECTRIC						
FEBE01	Replace Bucket Truck #8		0			Completed 12/2015	O
FEBE02	Replace Digger Truck #17		0			Completed 12/2015	O
FEBE03	Replace Pickup Truck #24		0			Completed 10/2015	O
		Sub-Totals:	0	0			
		Grand Totals:	14,925.50	29,009.50	14,944.60		

Electric Category	2015		Budget Category

CONSTRUCTION BUDGET 2016 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETE D AMOUNT	AUTH AMOUNT	PROJECTE D AMOUNT	PROJECT STATUS	Electric Category
	BLANKETS ELECTRIC						
BABC16	Electric T&D Improvements	160100	976.6	1,138.20	1,106.80	Active	M
BABC17	Electric T & D Improvements	170100	0		0	Active	M
BACC16	2015 Electric T & D	150100	30	1,225.00	44.5	Completed 12/2016	M
BAOC16	T & D Improvements	140100	0	1,032.70	-7.9	Closed 3/2016	M
BBBC16	New Customer Additions	160101	286.7	294.9	337.2	Active	C
BBBC17	New Customer Additions	170101	0		0	Active	C
BBCC16	2015 New Customer Additions	150101	29.5	475	43.1	Closed 7/2016	C
BCBC01	Best Ave Boscawen Elementary School-Install Pole & OL	160144	0		2.5	Completed 12/2016	C
BCBC16	Outdoor Lighting	160102	101.3	143.6	145.6	Active	M
BCBC17	Outdoor Lighting	170102	0		0	Active	M
BCBC19	Outdoor Lighting 2017	17002	0			Active	M
BCCC15	Outdoor Lighting	140102	0		0	Closed 3/2016	M
BCCC16	2015 Outdoor Lighting	150102	4	132	2.7	Closed 4/2016	M
BDBC16	Emergency & Storm Restoration	160103	573.4	500	467.6	Active	M
BDBC17	Emergency & Storm Restoration	170103	0		0	Active	M
BDCC16	2015 Emergency & Storm	150103	11.8	574.3	-70.6	Completed 5/2016	M
BDOC16	Emergency & Storm	140103	0	622.3	0	Closed 3/2016	M
BEBC16	Billable Work	160104	210.5	285	315.4	Active	M
BEBC17	Billable Work	170104	0		0	Active	M
BECC16	2015 Billable Work	150104	8.9	281.8	-65.9	Completed 7/2016	M
BEOC16	Billable Work	140104	0	191.6	13.3	Closed 3/2016	M
BFBC16	2016 Transformer Purchases-Company	160105	106.6	60	29.4	Active	I
BFBC17	2017 Transformer Purchases - Company	170105	0		0	Active	I
BFCC16	2015 Transformer Purchases-Company	150105	0		0	Closed 5/2016	I
BGBC16	2016 Transformer Purchases-Customer	160106	620.6	619.2	551.4	Active	C
BGBC17	2017 Transformer Purchases - Customer	170106	0		0	Active	C
BGCC16	2015 Transformer Purchases-Customer	150106	13.7	647.8	30.5	Closed 8/2016	C
BHBC16	2016 Meter Purchases-Company	160108	83.1	133	107.2	Active	M
BHBC17	2017 Meter Purchases - Company	170108	0		0	Active	M
BHOC16	2015 Meter Purchases-Company	150108	0		0	Closed 2/2016	M
BIBC16	2016 Meter Purchases-Customer	160107	141.7	208	195.2	Active	C
BIBC17	2017 Meter Purchases - Customer	170107	0		0	Active	C
BIOC16	2015 Meter Purchases-Customer	150107	0		0	Closed 2/2016	C
		Sub-Totals:	3,198.50	8,564.40	3,248.00		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETE D AMOUNT	AUTH AMOUNT	PROJECTE D AMOUNT	PROJECT STATUS	
	COMMUNICATIONS ELECTRIC						
ECEC01	Two way radio replacements	160115	5	5	2.7	Active	O
ECEC02	AMI Equipment - Unanticipated Replacements	160123	21.5	21.4	29.6	Active	O
EECC02	Replace and Upgrade Electric SCADA Master	150133	17.4	221.5	16.3	Completed 3/2016	O
		Sub-Totals:	43.9	247.9	48.6		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETE D AMOUNT	AUTH AMOUNT	PROJECTE D AMOUNT	PROJECT STATUS	
	COMMUNICATIONS GENERAL						
ECNC01	2016 IT Infrastructure	160124	0	145.9	50.7	Active	O
ECNC02	GPS OMS - Interface	160126	0	3.5	3.5	Active	O
ECNC03	First Responder - Municipal Trouble Reporting App	160133	0	17.2	18.2	Active	O
ECNC04	2016 Cyber Security Enhancements	160137	0	9.7	0.6	Active	O
ECNC05	Unify Workforce Management System	160142	0	18.5	15.9	Active	O
ECNC06	ITRON MVRS Upgrade	160145	0	9.4	4.2	Active	O
ECNC08	General Software Enhancements	160150	0	16.5	3.3	Active	O
ECNC09	Upgrade Critical Integration/Interface Jobs	160164	0	7.9	0	Active	O
ECNC10	DPU ORP System	160171	0	25.5	24.2	Active	O
ECNC12	MV-90 xi TCIP Network Functionality and License	150176	0	11.5	11.5	Completed 8/2016	O
ECOC01	Two Way Radio Replacements	150114	0	4	0	Completed 4/2016	O
ECOC02	AMI Equipment, Unanticipated Replacements	150120	0	43.5	0	Completed 3/2016	O
ECOC04	2015 Infrastructure	150127	0		2.5	Closed 5/2016	O
ECOC05	Electric Inspections	150128	0	52	6.3	Active	O
ECOC06	GIS Version Upgrade & Data Model Consolidation	150129	0	94.4	44.1	Active	O
ECOC07	Upgrade Generator Interconnection Database	140141	0	19.6	14.1	Active	O
ECOC08	Municipal Maps and Reports	150134	0		0	Active	O
ECOC09	24 Hour Damage Assessment/Field Restoration	140146	0	60.1	7.3	Active	O
ECOC10	Enhancements for Third Party Attachments-ODI Plant Records	150136	0	17	0	Active	O
ECOC11	Vehicle GIS/Garmin Overlay	140177	0		0	Completed 8/2016	O
ECOC12	General Software Enhancements	150143	0	9.9	14.3	Active	O
ECOC13	EETS Enhancements 2015	150169	0	9.9	24.8	Active	O
ECOC14	2015 Cyber Security Enhancements	150170	0	17.2	0.4	Active	O
		Sub-Totals:	0	593.3	245.9		
BUDGET		AUTH	BUDGETE D	AUTH	PROJECTE D	PROJECT	

Electric Category	2016
Growth	
Customer Additions (C)	1,463,600
Subtotal Growth	1,463,600
Non-Growth	
Reliability (R)	201,800
Maintenance Replacement (M)	2,896,400
Mandated (H)	700,300
System Improvement (I)	5,929,400
Grid Modernization (G)	0
Other (O)	470,100
Subtotal Non-Growth	10,198,000
Total	11,661,600
	11,661,600
	0

Budget Category	
Annual Requirements Blankets	**2016**
T&D Improvements	1,143,400
New Customer Additions	382,800
Outdoor Lighting	148,300
Emergency & Storm Restoration	397,000
Billable work	262,800
Transformers	611,300
Meters	302,400
Sub-Totals:	**3,248,000**
Distribution	
Overhead Line Extensions over $20,000	42,000
Underground Line Extensions over $20,000	263,700
Street Light Projects	(400)
Telephone Company Requests	-
Highway Projects	700,300
Distribution Pole Replacements	694,900
Specific Projects: Distribution	216,800
Sub-Totals:	**1,917,300**
Substation	
Specific Projects: Substation	6,119,400
Sub-Totals:	**6,119,400**
Communications	**294,500**
Tools, Shop, Garage	**66,900**
Laboratory	**6,300**
Office	**2,200**
Structures	**7,000**
Distribution Totals:	**11,661,600**

CONSTRUCTION BUDGET 2016 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
NUMBER	DESCRIPTION	NUMBER	AMOUNT	AMOUNT	AMOUNT	STATUS	
	DISTRIBUTION ELECTRIC						
DABC00	Overhead Line Extensions		68.4		42.2	Active	C
DABC01	75 New Rd Canterbury-2 Pole OH Line Ext-Billable	160125	0	6.2	8.4	Active	
DABC02	Center Rd L# 44 Chichester-OH Line Ext-Non-Billable	160129	0	10.7	18.8	Closed 12/2016	
DABC03	5 Pleasant View Ave-One P OH Line Ext	160155	0			Active	
DABC04	Concord Hospital-Langley Parkway Line Relocation	160156	0		-0.7	Closed 12/2016	
DABC05	102 Woodhill Rd Bow-3 pole OH line ext-Billable	160157	0	10.3	15.5	Completed 11/2016	
DABC07	283 Shaker Rd Concord-One Pole Line Ext-Billable	160167	0	5.8	2.7	Active	
DABC08	53 South Bow Rd-OH Line Extension -Billable	160168	0	9.3	-3.4	Active	
DACC00	Overhead Line Extensions - Carryover		4.8		-0.2	Completed 11/2016	C
DACC01	250 Pleasant St-Concord Hospital-relocate pole	150162	0		2	Closed 3/2016	
DACC02	195 N Main St Boscawen -install 3 25kVA transf for 3 ph serv	150175	0		-2.2	Completed 11/2016	
DBBC00	Underground Line Extensions		111.4		224.6	Active	C
DBBC01	7 Penacook St Penacook-Wasterwater Treatment Plant-Billable	160127	0	7.2	-0.5	Active	
DBBC02	Tremont St Boscawen-California Fields-Primary urd line ext-Billable	160128	0	46.4	59.8	Active	
DBBC03	Julie Dr Concord-urd sub division-Billable	160134	0	41.6	38.7	Active	
DBBC04	250 Pleasant St-Urd Line Extension for OL's	160140	0		0.2	Closed 12/2016	
DBBC05	103 West Parish Rd-Underground Line Ext-Non-Billable	160139	0	4.6	8.2	Active	
DBBC08	121 Water St-OH to Urd-Non-billable	150164	0		0	Cancelled 1/2016	
DBBC09	121 Water St Boscawen-OH to Urd-Billable	150163	0		27.8	Cancelled 2/2016	
DBBC12	State of NH Liquor Commission 50 Storrs St-3 ph Line Ext-Billable	160143	0	3.5	9	Active	
DBBC13	The Woods of Bow Dev-Parson's Way Phase III-urd line ext	160146	0	9.2	5.9	Closed 12/2016	
DBBC14	94 Manchester St-Concord Key Collision-urd line ext-Billable	160147	0	39.5	45.9	Completed 11/2016	
DBBC15	20 Broken Bridge Rd Concord-INATGAS-1 p 3ph urd line ext-nonbillable	160152	0	95.2	20.5	Active	
DBBC16	Plum St Concord-Primary urd line ext	160153	0	1.3	0.7	Completed 11/2016	
DBBC17	Goldenrod Ln Bow-primary urd line ext	160154	0	1.8	1.8	Closed 12/2016	
DBBC18	1 Knox Rd-Bow Safety Complex 3 ph urd primary line extension	160161	0	10.4	6.8	Active	
DBCC00	Underground Line Extensions, Carryover		13.4		39.1	Active	C
DBCC01	Stonesled Farms Ph 2 Lewis Ln Bow-urd line ext	150150	0	33.6	-1.1	Closed 3/2016	
DBCC02	273 Old Loudon Rd 3 ph primary urd line ext	150151	0	18	-11.3	Closed 3/2016	
DBCC03	Triangle Park Dr 3 ph primary urd line ext	150152	0	31.7	2.1	Closed 9/2016	
DBCC04	4 Thibeault Dr Bow3 ph line primary urd line ext	150153	0	52.6	20	Closed 3/2016	
DBCC05	12 Cross St Penacook Sing Ph Urd Line Ext-Billable	150154	0	13	3.6	Active	
DBCC06	The Woods of BowDev-Parson's Way Ph2 urd line ext	150155	0	13	13.3	Closed 8/2016	
DBCC07	115 Appleton St Concord-OH to Urd-Billable	150158	0	3.9	7.4	Closed 5/2016	
DBCC08	121 Water ST Boscawe-OH to Urd Billable	150167	0	5	-4.2	Closed 10/2016	
DBCC09	34 Reserve Pl-Sing Ph Urd Line Ext	150174	0	5.4	9.3	Closed 12/2016	
DCBC00	Street Light Projects		8.5		-0.4	Active	M
DCBC01	Stickney Ave Concord-Relocating Parking OL's	160136	0		-0.4	Closed 12/2016	
DCCC00	Street Light Projects, Carryover		0			Completed 2/2016	M
DDBC00	Telephone Company Requests		35.9			Active	H
DDCC00	Telephone Company Request - Carryover		3.4			Completed 1/2016	H
DEBC00	Highway Projects		82.3		558.8	Active	H
DEBC01	Relocate OH to UG Along S Main St., Concord	160132	0	76	0	Completed 1/2016	
DEBC02	TIGER Main Street Project-Pleasant St to Thompson St Concord	160141	0		540.6	Active	
DEBC03	1 Knox Rd Bow-Bow Safety Complex-Relocate Primary-Billable	160162	0	1.7	20.2	Active	
DEBC04	Relocate Pole 70 for Hospital Entrance Widening - Pleasant St., Concord	150161	0		0	Cancelled 1/2016	
DEBC05	Exit 17 off I-93 Concord/Canterbury -Repair Electr pull box	160170	0		-2	Active	
DECC00	Highway Projects, Carryover		7.9		141.5	Active	H
DECC01	106 Airport Rd-NewOL's Banks Chevorlete	150172	0		25.1	Closed 8/2016	
DECC02	Install Push Brace, Relocate Quad, Remove Pole 18-1A	150160	0		-4.3	Closed 11/2016	
DECC03	Sewalls Falls Bridge-Relocate Pole Line	150173	0		138.4	Active	
DECC04	Pole Relocation for Bridge Replacement - State of NH	140168	0		-4	Closed 12/2016	
DECC05	Relocation of Aluminum Light Standards and Removal of Hi Mast	2254	0		-13.8	Closed 10/2016	
DPBC01	Distribution Pole Replacement	160111	579.7	625.5	694.9	Closed 12/2016	M
DPBC02	New Subtransmission Lines - Broken Ground to Hollis	160158	487.5	897	0	Active	I
DPBC07	Transpose 374 & 375 Lines out of Garvins		141.8			Cancelled 4/2016	I
DPBC11	Manhole improvements		100.2			Cancelled 10/2016	M
DPCC01	Relocate 396X1 tap	150148	99.9		17	Closed 10/2016	M
DPNC01	Replace Failed UG Cable - MH 25 to School Street. Concord	160166	0	44.9	0	Active	M
DPNC02	Replace Failed UG Cable - MH 24 to MH 25 - N State St., Concord	160172	0	47.8	0	Active	M
DPNC89	Best Ave Boscawen Elementary School-Install Pole & OL	160144	0		-2	Active	C
DPOC01	Distribution Pole Replacements	150126	0		0	Closed 10/2016	M
DPOC02	Replace Failed Pri UG - Pads 2-3 - Broken Ground Dr., Concord	150131	0		0	Cancelled 1/2016	M
DPOC03	Install New Underground Switch, 211P, MH25	13218	0		0	Closed 11/2016	I
DRBC00	Reliability Projects		388.9		171.2	Active	R
DRBC07	URD Cable injection project Middlebury St	160163	0	225.1	171.2	Active	
DRCC00	Reliabilty Projects, Carryover		0			Completed 2/2016	R
DROC01	Install Fusesaver device on pole # 130 Bow Bog Rd and P# 28 New Orchard Rd. Epsom	150157	0	9.2	6.6	Closed 3/2016	R
DROC02	Reliability Improvements on 34.5 KV main lines and Sub Trans lines	150168	0	91.8	24	Closed 10/2016	R
		Sub-Totals:	2,133.90	2,498.00	1917.3		

Electric Category	2016	Budget Category

CONSTRUCTION BUDGET 2016 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE ELECTRIC						
EAEC01	Tools, Shop & Garage, Normal replacements	160116	13.5	13.5	16.8	Active	O
EAEC02	Purchase and replace rubber goods	160117	5	5	4.3	Active	O
EAEC03	Purchase and replace Hot Line Tools	160118	3.3	3.3	2.7	Active	O
EAEC05	Purchase new Tracemaster Dig Safe Locating Machine	160120	3	3	3.4	Completed 3/2016	O
EAEC06	Purchase new stick saw for truck # 23	160119	1.8	1.8	1.1	Active	O
EAEC07	Purchase Non-Entry Manhole rescue system	160131	2	2.3	2.4	Completed 6/2016	O
EAEC08	Normal additions & replacement - tools & equipment Metering	160112	7	7	6.4	Active	O
EENC01	Purchase grounding mat for Mobile substation	160151	0	23	22.2	Active	O
EEOC01	NH ESCC RTU Replacement	13293	0		0	Closed 11/2016	O
		Sub-Totals:	35.6	58.9	59.3		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE GENERAL						
EACC01	Purchase tools for new Bucket Truck # 25	160165	5	5	7.1	Active	O
EAOC01	Electric Tools, Shop & Garage normal replacements	150115	0	13.5	0	Completed 1/2016	O
EAOC02	Purchase and replace Rubber Goods	150122	0	5	0	Completed 1/2016	O
EAOC03	Purchase and Replace Hot Line Tools	150123	0		0.3	Closed 11/2016	O
EAOC04	Normal additions & replacement - tools & equipment Metering	150110	0		0.2	Closed 11/2016	O
EAOC05	Normal Replacement and Additions Substation Tools	150119	0		0	Closed 3/2016	O
EAOC06	Purchase Bierer ST800 Service Tester	150124	0		0	Closed 11/2016	O
		Sub-Totals:	5	23.5	7.6		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	LABORATORY GENERAL						
EBBC01	Lab Equipment - Normal Additions and Replacements	160113	7	7	5.9	Active	O
EBOC01	Lab Equipment - Normal Additions and Replacements	150111	0		0.4	Closed 11/2016	O
		Sub-Totals:	7	7	6.3		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE ELECTRIC						
EDEC03	Office Furniture and Equipment-Replacements	160121	6	6	2.2	Active	O
		Sub-Totals:	6	6	2.2		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE GENERAL						
EDOC01	Office Furniture and Equipment	150125	0		0	Closed 11/2016	O
		Sub-Totals:	0	0	0		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	STRUCTURES GENERAL						
GPBC01	Normal Improvements to Capital Facility	160114	12	12	7	Active	O
GPCC01	CAPITAL - Relocate SCADA Equipment	13248	13	20.6	0	Active	O
GPCC02	Electrical systems and life safety upgrades	13243	32	46.3	0	Active	O
GPOC01	Normal Improvements to Capital Facility	150113	0		0	Closed 11/2016	O
		Sub-Totals:	57	78.9	7		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	SUBSTATION ELECTRIC						
SPBC01	Hollis S/s - Upgrades to Accomodate Broken Ground	160159	195	1,462.50	0	Active	I
SPBC02	Replace Battery Bank	160122	32.6	46.4	48.2	Active	O
SPCC01	Broken Ground - Site Evaluation, Permitting, Preliminary Survey	140144	6,175.00	12,620.00	5,897.50	Active	I
SPCC02	Replace Bridge Street Transfer Trip - PSNH Garvins Rebuild		56.1			Cancelled 4/2016	O
SPCC03	Transformer 7T1 Replacement at Bow Junction and Purchase Spare Transformer	140161	25	616.2	2.5	Closed 12/2016	I
SPNC01	Replace Failed 7C1 Cap Bank	160130	0		35.9	Completed 8/2016	O
SPNC02	Replace transformer 13.8kV bushings	160135	0		31.5	Completed 10/2016	M
SPOC01	West Concord 2H1 & 2H2 - Eliminate AC Tripping	150138	0		9.1	Closed 11/2016	O
SPOC02	Purchase- Maintenance Reporting Database for Substations	150130	0	31.2	0	Completed 3/2016	O
SPOC03	Crushed Stone in Substations	150121	0		0	Closed 3/2016	O
SPOC06	Replace Regulator on 1H3 Phase B	150146	0		11.3	Closed 2/2016	M

Electric Category	2016		Budget Category

CONSTRUCTION BUDGET 2016 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
SPOC07	Replace Regulator on 3H2 Phase B	150147	0		0	Closed 11/2016	M
SPOC08	Replace Failed Recloser at Substation	150149	0		0	Closed 10/2016	M
SPOC09	Replace Failed Motor Operator on the 374J4 Switch	150156	0		7.9	Closed 11/2016	M
SPOC10	Replace Failed 1H1 and 2H2 Regulators	150166	0		30.8	Closed 11/2016	M
SPOC11	Replace Failed Regulator on Dover Rd Chichester	150171	0	40.2	40.6	Closed 11/2016	M
SPOC12	SPU 3000 Failures during Snowstorm	140184	0	30	0	Completed 10/2016	M
SPOC13	Replace Failed Cap Bank, RTU and Regulators due to a Fault	140133	0		4.1	Completed 8/2016	M
SPOC14	Purchase SPU for failed Bow Junction Unit	140164	0	14	0	Completed 3/2016	O
		Sub-Totals:	6,483.70	14,860.40	6119.4		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TRANSPORTATION ELECTRIC						
FEBC01	Replace Bucket #25		0			Completed 12/2016	O
FEBC02	Replace pickup 41		0			Completed 6/2016	O
FEBC03	Replace pickup 40		0			Completed 6/2016	O
		Sub-Totals:	0	0			
		Grand Totals:	11,970.50	26,938.30	11,661.60		

Electric Category	2016		Budget Category

CONSTRUCTION BUDGET 2016 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	BLANKETS ELECTRIC						
BABE16	Electric T&D Improvements	161000	1,563.00	1,556.70	1,516.60	Active	M
BABE17	Electric T & D Improvements	171000	0		0.6	Active	M
BACE15	Electric T & D	141000	0		0	Closed 3/2016	M
BACE16	2015 Electric T&D	151000	74.3	1,507.20	-30.7	Active	M
BBBE16	New Customer Additons	161001	478.7	526.6	463.5	Active	C
BBBE17	New Customer Additions	171001	0		4.1	Active	C
BBCE15	New Customer Additions	141001	0		0	Closed 3/2016	C
BBCE16	2015 New Customer Additions	151001	18.9	550.5	6.4	Closed 10/2016	C
BCBE16	Outdoor Lighting	161002	276.5	274.6	233.9	Active	M
BCBE17	Outdoor Lighting	171002	0		0	Active	M
BCCE15	Outdoor Lighting	141002	0		0	Closed 3/2016	M
BCCE16	2015 Outdoor Lighting	151002	7	219.8	7.3	Active	M
BDBE16	Emergency & Storm Restoration	161003	423.4	396.9	430.6	Active	M
BDBE17	Emergency & Storm Restoration	171003	0		0	Active	M
BDCE15	Emergency & Storm	141003	0	400.8	0	Closed 3/2016	M
BDCE16	2015 Emergency & Storm	151003	16	484.5	-79.1	Active	M
BEBE16	Billable Work	161004	431.6	399.7	337.5	Active	M
BEBE17	Billable Work	171004	0		-14.7	Active	M
BECE16	2015 Billable Work	151004	24.5	390.1	-9.7	Active	M
BEOE16	Billable Work	141004	0	400.1	0	Closed 3/2016	M
BFBE16	2016 Transformer Purchases-Company	161005	55.2	107	100.4	Active	I
BFBE17	2017 Transformer Purchases - Company	171005	0		0	Active	I
BFCE15	Transformer Purchase-Company	141005	0		0	Cancelled 1/2016	I
BFCE16	2015 Transformer Purchases-Company	151005	0		0.5	Closed 8/2016	I
BGBE16	2016 Transformer Purchases-Customer	161006	1,151.30	1,368.20	1,045.90	Active	C
BGBE17	2017 Transformer Purchases - Customer	171006	0		0.1	Active	C
BGCE16	2015 Transformer Purchases-Customer	151006	30.7		35.9	Closed 5/2016	C
BHBE16	2016 Meter Purchases-Company	161008	154.7	180	198.6	Active	M
BHBE17	2017 Meter Purchases - Company	171008	0		0	Active	M
BHOE16	2015 Meter Purchases-Company	151008	0		5	Closed 8/2016	M
BIBE16	2016 Meter Purchases-Customer	161007	179	315	362.5	Active	C
BIBE17	2017 Meter Purchases - Customer	171007	0		0	Active	C
BIOE16	2015 Meter Purchases-Customer	151007	0		-3.9	Closed 5/2016	C
		Sub-Totals:	4,884.80	9,077.70	4,611.30		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS ELECTRIC						
ECEE01	Replace AMI Equipment	161025	21.5	21.4	3.8	Active	O
ECEE02	Two way radio replacements	161015	6	6	2.7	Active	O
		Sub-Totals:	27.5	27.4	6.5		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS GENERAL						
ECOE01	AMI Equipment, Normal Replacements	151037	0		9	Closed 11/2016	O
ECOE02	Two Way Radio Replacements	151018	0		0	Closed 2/2016	O
ECOE03	AMI - Guinea Switching PLX Permanent	141035	0		0	Closed 3/2016	O
ECOE04	Replace AMI SPU and Cell Modem	141034	0	9.3	0	Completed 3/2016	O
		Sub-Totals:	0	9.3	9		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	DISTRIBUTION ELECTRIC						
DABE00	Overhead Line Extensions - New Projects		83.2		52.6	Active	C
DABE01	Single Phase, Overhead Line Ext., 218 Haverhill Rd., East Kingston	161031	0	8.5	7.9	Closed 5/2016	
DABE02	Single Phase, Overhead Line Ext., 14 Nicholas Rd., Plaistow	161040	0	10	9.9	Closed 9/2016	
DABE03	Three Phase, Overhead Line Ext., 18 Dorre Rd., Kingston	161041	0	10.7	6	Closed 11/2016	
DABE04	Single Phase, Overhead Line Ext., Sarah's Way, Newton	161042	0	17.8	23.8	Closed 9/2016	
DABE05	Three Phase, O/H Line Ext, 1 Lafayette Rd, Hampton	161054	0	4.2	5	Closed 12/2016	
DACE00	Overhead Line Extensions, Carryover		14.5		8.4	Active	C
DACE01	Three Phase, O/H Line Ext., 31-33 Ocean Blvd., Hampton	151053	0		0	Closed 8/2016	
DACE02	Single Phase, Overhead Line Ext., 218 Haverhill Rd, East Kingston	151099	0		8.4	Closed 8/2016	
DBBE00	Underground Line Extensions - New Projects		276.9		346.8	Active	C
DBBE01	Extend Three Phase, 4 Commerce Dr., Atkinson	161030	0	3.9	-3.8	Active	
DBBE02	Single Phase, URD Line Ext., Rollins Farm Rd., Stratham	161032	0	76	82.2	Closed 12/2016	
DBBE03	Single Phase, URD Line Ext., 19 Powder Mill Rd, Exeter	161033	0	3.7	5	Closed 9/2016	
DBBE04	Single Phase, URD Line Ext., 44 Timber Swamp Rd., Hampton	161035	0	26.5	26.7	Closed 11/2016	
DBBE05	Single Phase, URD Line Ext., 12 Heron Dr., Danville	161036	0	8.1	10.4	Closed 11/2016	
DBBE06	Installation of Secondary Underground Service, Drakeside Rd., Hampton	161038	0	9	4.2	Active	
DBBE07	Single Phase, URD Line Ext., 263 Drakeside Rd., Hampton	161039	0	26.4	24.9	Closed 11/2016	

Electric Category	2016
Growth	
Customer Additions (C)	2,567,200
Subtotal Growth	2,567,200
Non-Growth	
Reliability (R)	144,300
Maintenance Replacement (M)	3,463,400
Mandated (H)	660,900
System Improvement (I)	4,763,500
Grid Modernization (G)	0
Other (O)	-73,200
Subtotal Non-Growth	8,958,900
Total	11,526,100
	11,526,100
	0

Budget Category	2016
Annual Requirements Blankets	
T&D Improvements	1,486,500
New Customer Additions	474,000
Outdoor Lighting	241,200
Emergency & Storm Restoration	351,500
Billable work	313,100
Transformers	1,182,800
Meters	562,200
Sub-Totals:	**4,611,300**
Distribution	
Overhead Line Extensions over $20,000	61,000
Underground Line Extensions over $20,000	591,700
Street Light Projects	(900)
Telephone Company Requests	301,200
Highway Projects	359,700
Distribution Pole Replacements	742,600
Specific Projects: Distribution	1,275,400
Sub-Totals:	**3,330,700**
Substation	
Specific Projects: Substation	3,496,500
Sub-Totals:	**3,496,500**
Communications	**15,500**
Tools, Shop, Garage	**50,300**
Laboratory	**7,100**
Office	**2,100**
Structures	**12,600**
Distribution Totals:	**11,526,100**

CONSTRUCTION BUDGET 2016 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DBBE08	Three Phase, URD Line Ext., 27 Brown Rd., Hampton Falls	161044	0	73.1	20.6	Active	
DBBE09	Three Phase, URD Line Ext., 80 Epping Rd, Exeter - Phase 1	161045	0	58.5	-5	Active	
DBBE10	Three Phase, URD Line Ext., 94 Tide Mill Rd., Hampton	161046	0		41.8	Closed 11/2016	
DBBE11	Three Phase, URD Line Ext., 9 Plaistow Rd., Plaistow	161047	0	10.8	15.5	Closed 12/2016	
DBBE12	Three Phase, URD Line Ext., 18 Continental Dr., Exeter	161048	0	8.9	11.2	Active	
DBBE13	Three Phase, URD Line Ext., 172 Main St., Sawmill Ridge, Phase 2	161049	0	27.4	26.7	Closed 11/2016	
DBBE14	Three Phase, URD Line Ext., 12 Continental Dr., Exeter	161050	0	49	62.6	Active	
DBBE15	Single Phase, URD Line Ext., Chandler Ave, Plaistow - Phase 1	161055	0	29.6	20.8	Active	
DBBE16	Three Phase, URD Line Ext., 603 Lafayette Rd., Seabrook	161057	0	33.3	-17	Active	
DBBE17	Single Phase, URD Line Ext., Folsom St., Exeter	161058	0	33.3	12.9	Completed 1/2016	
DBBE18	Remove O/H Secondary Lines, Install URD Line Ext., String Bridge, Exeter	161060	0		-12.4	Active	
DBBE19	Single Phase, URD Line Ext., Sawmill Ridge, Atkinson, Phase 3	161061	0	33.8	19.6	Closed 1/2016	
DBCE00	Underground Line Extensions, Carryovers		284.2		244.9	Active	C
DBCE01	Three Phase, URD Line Ext, 580 Winnacunnet Rd, Hampton	141036	0		0	Closed 1/2016	
DBCE02	Three Phase, URD Line Ext., Mill Rd., Kingston	151048	0		-49.1	Closed 2/2016	
DBCE03	Three Phase, URD Line Ext., 14-26 N St., Hampton	151055	0	58.8	-20.2	Closed 3/2016	
DBCE04	Single Phase, URD Line Ext., 22 Marshall Rd., Kingston	151057	0	87.7	20.5	Closed 2/2016	
DBCE05	Single Phase, URD LIne Ext., 2 Hampton Rd., Exeter	151063	0	76	9.2	Closed 2/2016	
DBCE06	Single Phase, URD Line Ext., 94 Black Snake Rd., Seabrook	151068	0	30	4	Completed 8/2016	
DBCE07	Three Phase, URD Line Ext., 27 Chestnut St.	151044	0	44.1	61.8	Closed 8/2016	
DBCE09	Single Phase, URD Line Ext., 86 Woodland Rd., Hampton	151078	0	26.9	33.8	Closed 5/2016	
DBCE10	Three Phase, URD Line Ext., 15 Industrial Way, Atkinson	151085	0	22.1	6.8	Closed 2/2016	
DBCE11	Three Phase, URD Line Ext., 377 Ocean Blvd, Hampton	151087	0	35.8	-1.3	Closed 8/2016	
DBCE12	Single Phase, URD Line Ext., off Patriots Rd., Strahtam	151088	0		0.7	Closed 2/2016	
DBCE13	Single Phase, URD Line Ext., off Smith Corner Rd., Plaistow	151089	0	37.9	-9.5	Closed 11/2016	
DBCE14	Three Phase, URD Line Ext, Sterling Hill, Exeter - Building 8	151090	0	7	15.4	Closed 9/2016	
DBCE15	Single Phase, URD Line Ext., Wild Pasture Rd., Kensington	151091	0	19.9	22	Closed 5/2016	
DBCE16	Three Phase, URD Line Ext., 146 Main St., Plaistow	151092	0		63.1	Closed 10/2016	
DBCE17	Single Phase, URD Line Ext., off North Main St., Newton	151093	0	31.1	27.8	Closed 9/2016	
DBCE18	Single Phase, URD Line Ext., 109 High St., Stratham	151094	0	32.4	40.8	Closed 8/2016	
DBCE19	Single Phase, URD Line Ext., 372 Exeter Rd., Hampton	151096	0	11.5	3.1	Closed 2/2016	
DBCE20	Single Phase, URD Line Ext., off Sweet Hill Rd., Plaistow	151098	0	27.3	34.2	Closed 5/2016	
DBCE21	Three Phase, URD Line Ext., 600 Lafayette Rd., Seabrook	141042	0	122.9	0	Active	
DBCE22	Three Phase, URD Line Ext., 7 Puzzle Ln., Newton	141076	0	19.5	-1	Closed 2/2016	
DBCE23	Three Phase, URD Line Ext., Mill Rd., Kingston	151048	0	5.3	0	Closed 2/2016	
DBCE24	Three Phase, URD Line Ext., 172 Main St., Atkinson, Phase 1	151069	0	82.8	-17.2	Closed 5/2016	
DCBE00	Street Light Projects		48.6		0	Active	M
DCBE01	Installation of Street Lighting, Provident Way, Lafayette Rd, Seabrook	151060	0		0	Closed 1/2016	
DCBE02	Installation of Street Lighting, Beckman Woods, Seabrook	151079	0		0	Closed 8/2016	
DCCE00	Street Light Projects, Carryover		0			Active	M
DCOE01	Installation of URD Secondary & Street Light, State Rt 125, Plaistow - 10044G	151084	0	0.6	-0.9	Closed 12/2016	M
DDBE00	Telephone Company Requests		0			Active	H
DDCE00	Telephone Requests, Carryover		304.5		301.2	Active	H
DDCE01	3353 Line Relocation, State Rt. 101, Hampton	141047	0	1,800.00	301.2	Active	
DEBE00	Highway Projects		551.8		366.2	Active	H
DEBE01	Relocate Overhead Facilities, State Rt 125, Plaistow	161009	0		211.4	Closed 11/2016	
DEBE02	Relocate Overhead Facilities, State Rt 1, Seabrook	161010	0	153.5	102.3	Closed 10/2016	
DEBE04	Replacement/Relocation of Poles, Lafayette Rd., Hampton	161051	0	48	52.6	Closed 11/2016	
Dec-00	Highway Projects, Carryover		0		-6.5	Active	H
DECE01	Relocation of Highway Light	141079	0		0	Active	
DECE03	Relocation of Poles, Lafayette Rd., Seabrook	151081	0		-6.5	Closed 2/2016	
DPBE01	Distribution Pole Replacements (REP), Various Locations	161011	640.1	638.7	742.6	Active	M
DPBE02	Relocate Main Line to Route 111, Kingston/Danville - Circuit 22X1	161014	1,399.10	1,830.80	423.6	Active	I
DPBE03	Rebuild Country Pond Road to Three-Phase	151035	0		0	Closed 1/2016	I
DPBE04	Reconductor Portsmouth Ave, Seabrook Beach	151030	0		0	Closed 1/2016	I
DPBE05	Reconductor Portions of 2X3, 23X1 and 15X1	151010	0		0	Completed 1/2016	I
DPCE01	Rebuild and Convert Maple Ave and Main Street, Plaistow - Circuits 5H1/5X3 (new)	151072	55.8	376.2	248.7	Closed 11/2016	I
DPCE02	Winnacunnet Road Tap - Install Regulation	141021	247.3	386.1	156.4	Closed 12/2016	I
DPNE01	Convert Exeter Road and Rebuild Brown Road to Three Phase, Hampton Falls Circuits 2X3 & 18X1	161034	0	92.3	43.7	Active	I
DPNE02	Distribution Upgrades to Accommodate Foss Manufacturing, Hampton	161037	0	525	271.4	Active	I
DPNE04	Replace Overhead Pole Line with Underground Facilities for PEA	161053	0		-207.7	Active	O
DPNE05	Upgrade Neutral Along a Portion of Circuit 5H2, Plaistow	161056	0	83	0	Active	I
DPNE06	Replace H-Structure and Changeover	161059	0	39.4	39.4	Completed 1/2016	M
DPNE09	Improve Voltage along Wentworth Street, Exeter	151074	0		0	Closed 8/2016	I
DPNE25	SnowStorm - November 26	141081	0		0	Completed 1/2016	M
DPOE01	Upgrade Stard Road Tap	151066	0	230	51.5	Active	I
DPOE02	Replace the 03341 and the 3352 Reclosers at Wolf Hill	13161	0	154.6	39.2	Completed 9/2016	M
DPOE04	Replace Three Phase Failed Primary Underground Cable, Chase's Way, Seabrook	151071	0	50.9	0	Closed 12/2016	M
DPOE05	Reconstruct Overhead Pole Line, Highland Ave., Hampton	151097	0	85	47.2	Closed 5/2016	M
DPOE06	Convert Ashworth Ave to 8 kV, Circuit 3W4	151041	0	170	17.7	Closed 10/2016	I

Electric Category	2016

Budget Category

CONSTRUCTION BUDGET 2016 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DPOE07	Replace Direct Buried Underground Facilities, 32 Industrial Dr., Exeter	141055	0		0	Closed 1/2016	M
DRBE00	Reliabilty Projects		0		19.2	Active	R
DRBE05	Replace manually operated switches with automated switches, 3343 and 3354 Lines	151056	0		19.2	Active	
DRCE00	Reliability Carry-overs		221.4		90.3	Active	R
DRCE01	Replace manually operated switches with automated switches, 3343 and 3354 Lines	151056	0	400.5	73.5	Completed 7/2016	
DRCE02	New Boston Road Tap - Install Reclosers	151043	0	302	16.9	Completed 8/2016	
DROE01	Install Motor Operated Air Breaks on 3362 & 3351 lines, RTU and SCADA	151058	0	150	0.1	Active	R
DROE03	Hampton S/S - Install Protective Devices on 3342, 3353 and 3348	13170	0	645.1	34.7	Active	R
		Sub-Totals:	4,127.40	9,503.70	3330.7		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE ELECTRIC						
EAEE01	Tools, Shop & Garage - Normal Additons and Replacements	161017	13.5	13.5	17.7	Active	O
EAEE02	Purchase and Replace Rubber Goods	161018	5.5	5.5	5.5	Active	O
EAEE03	Purchase and Replace Hot Line Tools	161019	3.5	3.5	2.8	Active	O
EAEE04	Normal additions & replacement - tools & equipment Meter and Services	161012	7	7	0	Active	O
EAEE05	Normal Replacements Tools - Substation	161024	7	7	3.1	Active	O
EAEE06	Purchase/Replace Tooling for Bucket Truck #23	161020	6.5	6.5	1	Active	O
EAEE07	Replace Underground Locating Equipment	161021	3		3.4	Closed 11/2016	O
EEOE01	Replace Seabrook Marsh RTU	13193	0	20.4	0.1	Active	O
		Sub-Totals:	46	63.4	33.6		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE GENERAL						
EANE02	Replace Tooling for Bucket Truck #33 - Damaged in Fire	161029	0	6	2.2	Active	O
EAOE02	Purchase and Replace Rubber Goods	151024	0		2.3	Closed 12/2016	O
EAOE03	Purchase and Replace Hot Line Tools	151025	0		1.5	Closed 11/2016	O
EAOE04	Normal additions & replacement - tools & equipment Metering	151012	0		0.2	Closed 11/2016	O
EAOE05	Normal Additional Substation Tools	151026	0		0	Closed 5/2016	O
EAOE06	Purchase/Replace Tooling for New Bucket Truck #8	151031	0		0.3	Closed 12/2016	O
EAOE07	Purchase/Replace Tooling for New Digger Truck #17	151032	0	3.5	7.9	Closed 12/2016	O
EAOE08	Tools, Shop & Garage - Normal Additions and Replacements	151023	0		2.3	Closed 12/2016	O
		Sub-Totals:	0	9.5	16.7		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	LABORATORY GENERAL						
EBBE43	Lab Equipment normal additions and replacements	161027	7	7	6.7	Active	O
EBOE01	Lab Equipment - Normal Additions and Replacements	151013	0		0.4	Closed 11/2016	O
		Sub-Totals:	7	7	7.1		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE ELECTRIC						
EDEE01	Office Furniture and Equipment-Replacements	161022	3.5	3.5	2.1	Active	O
		Sub-Totals:	3.5	3.5	2.1		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE GENERAL						
EDOE01	Office Furniture and Equipment	151021	0	6	0	Active	O
		Sub-Totals:	0	6	0		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	STRUCTURES GENERAL						
GPBE01	Normal Improvements to Seacoast Facility	161013	15	15	12.6	Active	O
GPBE02	Physical Security Facility Upgrades & Additions	151019	0		0	Active	O
GPCE01	Electric system/life safety upgrades	13146	40	51.6	0	Active	O
GPOE01	Normal Improvements to Seacoast Facility	151016	0		0	Closed 11/2016	O
GPOE02	Physical Security Facility Upgrades & Additions	151019	0	35	0	Active	O
		Sub-Totals:	55	101.6	12.6		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	SUBSTATION ELECTRIC						

Electric Category	2016

Budget Category

CONSTRUCTION BUDGET 2016 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
SPCE01	Kingston Substation-System Supply	13184	2,925.00	12,705.60	2,903.70	Active	I
SPCE02	Build New 5X3 Distribution Circuit Position in Plaistow Substation	151076	280.8	556.1	545.9	Active	I
SPNE01	Guinea 18X1 - Replace Breaker and Relaying	161052	0	237.9	2.6	Active	O
SPOE01	Crushed Stone in Substations	151027	0		4.8	Closed 5/2016	O
SPOE02	Guinea 18C2 and 18C3 - Replace Switches and Unground	151011	0	188.8	36.6	Closed 12/2016	O
SPOE04	Replace Regulator on 7X2 Phase C	151067	0		2.9	Closed 11/2016	O
		Sub-Totals:	3,205.80	13,688.40	3,496.50		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TRANSPORTATION ELECTRIC						
FEBE01	Replace bucket truck #23		0			Completed 12/2016	O
FEBE02	Replace Pick Up Truck #16		0			Completed 6/2016	O
FEBE03	Replace Pick Up Truck #34		0			Completed 6/2016	O
		Sub-Totals:	0	0			
		Grand Totals:	12,357.00	32,497.40	11,526.10		

Electric Category	2016		Budget Category

CONSTRUCTION BUDGET 2017 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	BLANKETS ELECTRIC						
BABC17	Electric T & D Improvements	170100	1,113.70	1,188.00	1,385.40	Active	M
BABC18	Electric T&D Improvements	180100	0		0	Active	M
BACC17	Electric T&D Improvements	160100	28.6	1,138.20	118.7	Active	M
BAOC17	2015 Electric T & D	150100	0	1,225.00	0	Completed 1/2017	M
BBBC17	New Customer Additions	170101	312.9	420	471.7	Active	C
BBBC18	New Customer Additions	180101	0		-0.5	Active	C
BBCC17	New Customer Additions	160101	39.6	294.9	11.2	Completed 5/2017	C
BCBC17	Outdoor Lighting	170102	111.8	106.2	102.8	Active	M
BCBC18	Outdoor Lighting	180102	0		0	Active	M
BCCC17	Outdoor Lighting	160102	4.7	143.6	0.2	Completed 5/2017	M
BDBC17	Emergency & Storm Restoration	170103	752.4	753	1,420.30	Active	M
BDBC18	Emergency & Storm Restoration	180103	0		0	Active	M
BDCC17	Emergency & Storm Restoration	160103	13.3	500	-71.1	Completed 10/2017	M
BDOC17	2015 Emergency & Storm	150103	0	574.3	0	Completed 2/2017	M
BEBC01	5 Quincy Rd Concord-Installation of a Pad & wire for Subdiv lot	170143	0		3.3	Closed 11/2017	M
BEBC17	Billable Work	170104	237	237	291.4	Active	M
BEBC18	Billable Work	180104	0		0.1	Active	M
BECC17	Billable Work	160104	9.7	285	-50.3	Completed 9/2017	M
BEOC17	2015 Billable Work	150104	0	281.8	0	Completed 2/2017	M
BFBC17	2017 Transformer Purchases - Company	170105	97.7	50	5.3	Active	I
BFBC18	Transformer Purchases - Company Conversions	180105	0		0	Active	I
BFCC17	2016 Transformer Purchases-Company	160105	0		3.1	Closed 10/2017	I
BGBC17	2017 Transformer Purchases - Customer	170106	644	644	877.5	Active	C
BGBC18	Transformer Purchases - Customer Requirements	180106	0		0	Active	C
BGCC17	2016 Transformer Purchases-Customer	160106	14		147.9	Closed 10/2017	C
BHBC17	2017 Meter Purchases - Company	170108	107.1	107.1	118.9	Active	M
BHBC18	Electric Meter Purchases - Company	180108	0		0	Active	M
BHOC17	2016 Meter Purchases-Company	160108	0		6.9	Closed 4/2017	M
BIBC17	2017 Meter Purchases - Customer	170107	404	404	288.4	Active	C
BIBC18	Electric Meter Purchases - Customers	180107	0		0	Active	C
BIOC17	2016 Meter Purchases-Customer	160107	0		31	Closed 4/2017	C
		Sub-Totals:	3,890.50	8,352.10	5,162.20		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS ELECTRIC						
ECEC01	Two Way Radio Replacements	170114	3	3	1.1	Active	O
ECEC02	AMI Equipment, Unanticipated Replacements	170123	22.5	38	29.1	Active	O
		Sub-Totals:	25.5	41	30.2		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS GENERAL						
ECNC01	Meter data archiving plan	170127	0	9.2	3.1	Active	O
ECNC02	Replace MV-90 communication bank modules	170128	0	6.7	0	Active	O
ECNC04	Electronic Time Sheet-Phase One	170130	0	28.1	4.6	Active	O
ECNC05	2017 Cyber Security Scheduled Replacements	170131	0	50.2	4.3	Active	O
ECNC06	Power Plant Upgrade 10.4 to 2016.1	170132	0	121.9	117.7	Closed 12/2017	O
ECNC07	2017 IT Infrastructure	170136	0	135.5	13.2	Active	O
ECNC08	Electric Inspections Version Upgrade	170151	0	38	0	Active	O
ECNC09	2017 General Software Enhancements	170157	0	16.5	8.4	Active	O
ECNC10	Eintake Miigration	170171	0	40	12.3	Closed 4/2017	O
ECNC11	IS Project Tracker Replacement	170172	0	9.9	1.9	Active	O
ECNC13	Meter Data Management	170177	0		2,398.50	Active	O
ECOC01	Two way radio replacements	160115	0		0	Closed 7/2017	O
ECOC02	24 Hour Damage Assessment/Field Restoration	140146	0	60.1	4.9	Active	O
ECOC03	Two Way Radio Replacements	150114	0		0	Closed 7/2017	O
ECOC04	AMI Equipment, Unanticipated Replacements	150120	0	43.5	-10	Closed 12/2017	O
ECOC05	Electric Inspections	150128	0		0	Closed 4/2017	O
ECOC06	GIS Version Upgrade & Data Model Consolidation	150129	0	94.4	27.7	Active	O
ECOC07	Upgrade Generator Interconnection Database	140141	0	56	2.7	Active	O
ECOC08	General Software Enhancements	150143	0		-13.7	Closed 4/2017	O
ECOC10	2015 Cyber Security Enhancements	150170	0		0	Closed 4/2017	O
ECOC11	AMI Equipment - Unanticipated Replacements	160123	0	29.6	1	Closed 12/2017	O
ECOC12	2016 IT Infrastructure	160124	0		11.9	Closed 4/2017	O
ECOC14	2016 Cyber Security Enhancements	160137	0		0	Closed 4/2017	O
ECOC15	Unify Workforce Management System	160142	0		0.6	Closed 4/2017	O
ECOC16	ITRON MVRS Upgrade	160145	0	9.4	0	Active	O
ECOC17	General Software Enhancements	160150	0	16.5	6	Closed 4/2017	O
ECOC18	Upgrade Critical Integration/Interface Jobs	160164	0		0	Cancelled 6/2017	O
ECOC19	EETS Enhancements 2015	150169	0	33.2	-0.2	Closed 4/2017	O
ECOC20	First Responder - Municipal Trouble Reporting App	160133	0	17.2	102.3	Closed 1/2017	O
ECOC21	Enhancements for Third Party Attachments-ODI Plant Records	150136	0	17	17	Closed 3/2017	O
		Sub-Totals:	0	832.9	2,714.20		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	DISTRIBUTION ELECTRIC						
DABC00	Overhead Line Extensions		80.7		28.6	Active	C
DABC01	110-118 Loudon Rd Red ArrowDiner- 3ph OH Line Ext-Billable	170112	0		4.8	Completed 12/2017	

Electric Category	2017
Growth	
Customer Additions (C)	1,919,000
Subtotal Growth	1,919,000
Non-Growth	
Reliability (R)	171,700
Maintenance Replacement (M)	4,296,300
Mandated (H)	-477,100
System Improvement (I)	3,959,800
Grid Modernization (G)	0
Other (O)	3,127,600
Subtotal Non-Growth	11,078,300
Total	12,997,300
	12,997,300
	0

Budget Category	2017
Annual Requirements Blankets	
T&D Improvements	1,504,100
New Customer Additions	482,400
Outdoor Lighting	103,000
Emergency & Storm Restoration	1,349,200
Billable work	244,500
Transformers	1,033,800
Meters	445,200
Sub-Totals:	**5,162,200**
Distribution	
Overhead Line Extensions over $20,000	38,700
Underground Line Extensions over $20,000	53,100
Street Light Projects	-
Telephone Company Requests	50,200
Highway Projects	(527,300)
Distribution Pole Replacements	751,500
Specific Projects: Distribution	2,199,600
Sub-Totals:	**2,565,800**
Substation	
Specific Projects: Substation	2,158,400
Sub-Totals:	**2,158,400**
Communications	**2,744,400**
Tools, Shop, Garage	**50,600**
Laboratory	**11,500**
Office	**2,300**
Structures	**302,100**
Distribution Totals:	**12,997,300**

CONSTRUCTION BUDGET 2017 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DABC02	41 Tremont St Boscawen-3 ph line extension-Billable	170141	0	15.3	20.2	Closed 12/2017	
DABC03	8 Gordon Rd Bow-3ph OH line Ext-Billable	170165	0	4.1	3.6	Completed 12/2017	
DACC00	Overhead Line Extensions - Carryover		9.1		10.1	Completed 2/2017	C
DACC01	75 New Rd Canterbury-2 Pole OH Line Ext-Billable	160125	0	6.2	0	Completed 1/2017	
DACC02	5 Pleasant View Ave-One P OH Line Ext	160155	0		-1	Closed 6/2017	
DACC03	102 Woodhill Rd Bow-3 pole OH line ext-Billable	160157	0		0	Closed 4/2017	
DACC04	283 Shaker Rd Concord-One Pole Line Ext-Billable	160167	0		0.6	Closed 4/2017	
DACC05	53 South Bow Rd-OH Line Extension -Billable	160168	0		10.5	Closed 4/2017	
DBBC00	Underground Line Extensions		130.1		27	Active	C
DBBC01	79 Dow Rd., Bow - Relocate Riser Pole	180109	0		-9.7	Closed 6/2017	
DBBC02	1113 Route 3A Bow-RYKEL Complex-PrimaryURD Line Ext	170138	0	18.4	-0.8	Active	
DBBC03	The Woods of Bow Dev-Parson's Way Ph III-compl urd line ext-Billable	170146	0	29	20.8	Active	
DBBC04	57 Ryan Rd Bow-3 ph urd line ext	170147	0	8.4	7.4	Closed 12/2017	
DBBC06	Vintage Estates, Sonoma Way Concord-singl ph urd line ext	170156	0	47	-51.6	Active	
DBBC07	6 Dunbarton Center Rd Bow-High Meadows-prim urd to two pads-billable	170162	0	38.4	4.1	Active	
DBBC08	163 N State St Merrimack County Court Primary Extend urd to pad	170169	0	20.2	-19.2	Completed 12/2017	
DBBC09	250 Pleasant St-Concord Hospital Memorial Bld-3 PH Primary urd to 3 ph transf	170170	0		1.1	Active	
DBBC10	76 Mountain Rd Epsom Getaway House-OH & URD Primary Line Extension-billable	170173	0	25.9	66.8	Completed 12/2017	
DBBC11	225 Water St Boscawen-OH to URD primary line ext-Non-Billable	170175	0	11.7	-7.8	Active	
DBBC15	20 Broken Bridge Rd Concord-INATGAS-1 p 3ph urd line ext-nonbillable	160152	0	95.2	1.6	Closed 12/2017	
DBBC17	Sunrise Meadows Senior Housing-Short Falls Rd Epsom urd line ext	170153	0	33	14.2	Active	
DBCC00	Underground Line Extensions, Carryover		14.4		26.1	Completed 11/2017	C
DBCC01	7 Penacook St Penacook-Wasterwater Treatment Plant-Billable	160127	0		5.7	Completed 2/2017	
DBCC02	Tremont St Boscawen-California Fields-Primary urd line ext-Billable	160128	0	46.4	-0.8	Completed 2/2017	
DBCC03	Julie Dr Concord-urd sub division-Billable	160134	0	41.6	5.2	Closed 12/2017	
DBCC04	Peaslee Hill Estates-Summer Ln Urd Line Extension	160138	0		10.9	Closed 6/2017	
DBCC05	12 Cross St Penacook Sing Ph Urd Line Ext-Billable	150154	0	13	-3.9	Completed 2/2017	
DBCC06	State of NH Liquor Commission 50 Storrs St-3 ph Line Ext-Billable	160143	0	3.5	6.9	Completed 2/2017	
DBCC08	Plum St Concord-Primary urd line ext	160153	0		0.8	Closed 4/2017	
DBCC09	1 Knox Rd-Bow Safety Complex 3 ph urd primary line extension	160161	0		1.2	Closed 6/2017	
DCBC00	Street Light Projects		9.3			Active	M
DCCC00	Street Light Projects - Carryover		1.5			Completed 4/2017	M
DDBC00	Telephone Company Requests		39.6		50.2	Active	H
DDBC01	Dunbarton Tel Requested Multiple Pole Replacements	170137	0	40.6	50.2	Completed 7/2017	
DDCC00	Telephone Company Request - Carryover		3.6			Completed 2/2017	H
DEBC00	Highway Projects		0		129.3	Active	H
DEBC01	CIP29 Exit 16 Roundabout - Concord	170140	0	189	113.9	Completed 8/2017	
DEBC02	1317 Route 3A Bow Auto Salvage-Primary urd to new pad	170145	0		0	Cancelled 7/2017	
DEBC04	Pole Relocations for Bridge Replacement Over White Brook	170164	0	13.9	15.4	Active	
DECC00	Highway Projects, Carryover		8.7		-520.9	Completed 2/2017	H
DECC01	TIGER Main Street Project-Pleasant St to Thompson St Concord	160141	0		-520.3	Completed 2/2017	
DECC02	1 Knox Rd Bow-Bow Safety Complex-Relocate Primary-Billable	160162	0	1.7	-2.6	Completed 2/2017	
DECC03	Exit 17 off I-93 Concord/Canterbury -Repair Electr pull box	160170	0		2	Completed 2/2017	
DEOC01	Sewalls Falls Bridge-Relocate Pole Line	150173	0		-135.7	Closed 4/2017	H
DPBC01	Condemned Poles quarter one 2017	170115	696.6	735.1	751.5	Active	M
DPBC02	Replace Chimney and riser	170168	104.8	60	32.4	Active	M
DPBC03	Circuit 6X3: Dunbarton Rd Step-down Replacement and Voltage Regulator Install		56.9			Active	I
DPCC01	New Subtransmission Lines - Broken Ground to Hollis	160158	845	2,750.00	1,871.20	Active	I
DPNC01	Replace Failed UG Cable - Pole 8 - Centerwood Dr., Concord	170148	0	27.9	28.6	Completed 9/2017	M
DPNC02	Replace Failed UG Cable - MH 24 to MH 25 - N State St., Concord	160172	0	47.8	47.6	Closed 7/2017	M
DPNC03	Replaced Failed Primary Cable - Portsmouth St., Concord	170152	0	37.7	0	Completed 9/2017	M
DPOC01	Replace Failed UG Cable - MH 25 to School Street. Concord	160166	0		48.1	Closed 7/2017	M
DRBC00	Reliabilty Projects		232.3		0	Active	R
DRBC01	Bow Junction Substation: Install an Auto Transfer Scheme		0			Cancelled 12/2017	
DRBC02	Circuit 8X3: Install a Fusesaver on Lane Road		0			Active	
DRBC03	Circuit 22W3: Install Sectionalizers on Birchdale Road, Bow	170139	0	10.2	0	Cancelled 6/2017	
DRBC04	374 Line: Install an Autosectionalizing Scheme		0			Cancelled 9/2017	
DRCC00	375 Line Automatic Sectionalizing at Terrill Park		160.6			Cancelled 12/2017	R
DROC01	URD Cable injection project Middlebury St	160163	0	225.1	44.8	Closed 12/2017	R
DROC13	Substation Reliability Improvements at Penacook	170166	0	172	67.6	Active	R
DROC15	Install 430 ft of conduit and 1/0 Al 35KV URD cable	170155	0	53.8	59.3	Completed 10/2017	R
		Sub-Totals:	2,393.20	4,822.00	2565.8		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE ELECTRIC						
EAEC01	Tools, Shop & Garage - Normal Additions and Replacements	170116	13.5	13.5	17.2	Active	O
EAEC02	Purchase and Replace Rubber Goods	170117	5.5	5.5	1.6	Active	O
EAEC03	Purchase and Replace Hot Line Tools	170118	3.3	3.3	7.1	Completed 11/2017	O
EAEC04	The normal addition and replacement of tools and equipment for the Electric Meter Department.	170110	7	7	7.6	Completed 12/2017	O
EAEC05	Normal additions & replacement - tools & equipment Substation	170122	7	7	9	Active	O
EEOC01	Replace and Upgrade Electric SCADA Master	150133	0	221.5	0	Closed 12/2017	O
EEOC02	Purchase grounding mat for Mobile substation	160151	0	23	0	Closed 12/2017	O
		Sub-Totals:	36.3	280.7	42.5		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE GENERAL						

Electric Category	2017

Budget Category

CONSTRUCTION BUDGET 2017 UES Capital

12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
EACC01	Purchase tools for new Bucket Truck # 23	170167	5	5	2.5	Active	O
EAOC01	Purchase and replace Rubber Goods	150122	0		0	Closed 7/2017	O
EAOC02	Normal additions & replacement - tools & equipment Metering	160112	0		0	Closed 7/2017	O
EAOC03	Tools, Shop & Garage, Normal replacements	160116	0		0.4	Closed 7/2017	O
EAOC04	Purchase and replace rubber goods	160117	0		4.1	Closed 7/2017	O
EAOC05	Purchase and replace Hot Line Tools	160118	0		0	Closed 7/2017	O
EAOC06	Purchase new stick saw for truck # 23	160119	0		1.1	Closed 7/2017	O
EAOC07	Purchase new Tracemaster Dig Safe Locating Machine	160120	0		0	Closed 7/2017	O
EAOC08	Purchase Non-Entry Manhole rescue system	160131	0	2.3	0	Completed 1/2017	O
EAOC09	Purchase tools for new Bucket Truck # 25	160165	0	5	0	Closed 12/2017	O
		Sub-Totals:	5	12.3	8.1		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	LABORATORY GENERAL						
EBBC01	Unscheduled Additions & Replacements Lab Instruments	170111	7	7	11.5	Completed 12/2017	O
EBOC01	Lab Equipment - Normal Additions and Replacements	160113	0		0	Closed 7/2017	O
		Sub-Totals:	7	7	11.5		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE ELECTRIC						
EDEC01	Office Furniture & Additions - Normal Additions & Replacements	170120	3.5	3.5	2.3	Active	O
		Sub-Totals:	3.5	3.5	2.3		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE GENERAL						
EDOC01	Office Furniture and Equipment-Replacements	160121	0		0	Closed 7/2017	O
		Sub-Totals:	0	0	0		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	STRUCTURES GENERAL						
GPBC01	Normal Improvement Capital DOC	170113	12	12	9.2	Active	O
GPBC02	Replace Roof at Capital DOC	170135	400	400	261.5	Active	O
GPBC03	Roof Hatch		20			Cancelled 3/2017	O
GPCC01	CAPITAL - Relocate SCADA Equipment	13248	13	20.6	13	Active	O
GPCC02	Electrical systems and life safety upgrades	13243	32	46.3	18.4	Active	O
GPOC01	Normal Improvements to Capital Facility	160114	0		0	Closed 7/2017	O
		Sub-Totals:	477	478.9	302.1		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	SUBSTATION ELECTRIC						
SPBC01	Bridge Street - Replace 35kV Line Relaying & Modify RTU		472.8			Cancelled 12/2017	O
SPBC02	Install Stone in Substation	170126	32.7	32.7	16.7	Active	O
SPBC03	Landgon S/S - Replace 374J5 & 375J6	170125	64.4	64.4	0	Active	O
SPCC01	Broken Ground - Site Evaluation, Permitting, Preliminary Survey	140144	1,950.00	12,620.00	1,479.00	Active	I
SPCC02	Hollis S/s - Upgrades to Accomodate Broken Ground	160159	1,267.50	1,462.50	601.2	Active	I
SPNC02	Replace 16H3 Recloser	170134	0	15	15	Closed 12/2017	M
SPNC03	Replaced Failed 2H1 Recloser	170142	0	78.5	0	Active	M
SPNC04	Replace Failed Operating Mechanism on the 13W1 Recloser	170161	0	30.6	31	Active	M
SPNC05	Replace 35kV Bushings on 3T1 at Gulf St S/S	170174	0	47.5	15.5	Active	M
SPOC01	Purchase SPU for failed Bow Junction Unit	140164	0		0	Closed 12/2017	M
SPOC02	SPU 3000 Failures during Snowstorm	140184	0	30	0	Closed 12/2017	M
SPOC03	Purchase- Maintenance Reporting Database for Substations	150130	0	31.2	0	Closed 12/2017	O
SPOC04	Replace Battery Bank	160122	0	46.4	0	Closed 12/2017	O
		Sub-Totals:	3,787.40	14,458.70	2158.4		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TRANSPORTATION ELECTRIC						
FEBC01	Replace pick up truck for Forester		0			Active	
FEBC02	Replace pickup #44		0			Active	
FEBC03	Replace bucket truck #23		0			Active	
FEBC04	Purchase New Reel Trailer		0			Active	
FEBC05	Purchase New Pole Trailer		0			Active	
		Sub-Totals:	0	0			
		Grand Totals:	10,625.40	29,289.10	12,997.30		

Electric Category	2017

Budget Category

CONSTRUCTION BUDGET 2017 UES Seacoast

12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	BLANKETS ELECTRIC						
BABE17	Electric T & D Improvements	171000	1,631.80	1,638.90	1,849.70	Active	M
BABE18	Electric T&D Improvements	181000	0		0	Active	M
BACE17	Electric T&D Improvements	161000	49.6	1,556.70	28	Active	M
BAOE17	2015 Electric T&D	151000	0	1,507.20	-2.7	Completed 3/2017	M
BBBE17	New Customer Additions	171001	589.7	559.4	504.1	Active	C
BBBE18	NewCustomer Additions	181001	0		-1.3	Active	C
BBCE17	New Customer Additons	161001	14.9	526.6	1.4	Active	C
BCBE17	Outdoor Lighting	171002	276.7	276.8	204.9	Active	M
BCBE18	Outdoor Lighting	181002	0		0	Active	M
BCCE16	2015 Outdoor Lighting	151002	0	219.8	-4.8	Closed 7/2017	M
BCCE17	Outdoor Lighting	161002	7.6	274.6	2.1	Active	M
BCOE17	2015 Outdoor Lighting	151002	0		0	Closed 7/2017	M
BCOE17	2015 Billable Work	151004	0		0	Completed 3/2017	M
BDBE17	Emergency & Storm Restoration	171003	418.4	434.5	673.7	Active	M
BDBE18	Emergency & Storm Restoration	181003	0		0	Active	M
BDCE16	2015 Emergency & Storm	151003	0	484.5	0	Closed 7/2017	M
BDCE17	Emergency & Storm Restoration	161003	17.4	396.9	8.1	Active	M
BDOE17	2015 Emergency & Storm	151003	0		0	Closed 7/2017	M
BEBE17	Billable Work	171004	507	410.1	270.4	Active	M
BEBE18	Billable Work	181004	0		0	Active	M
BECE16	2015 Billable Work	151004	0	390.1	-4	Completed 3/2017	M
BECE17	Billable Work	161004	0	399.7	-30.4	Active	M
BFBE17	2017 Transformer Purchases - Company	171005	135.9	200	138	Active	I
BFBE18	Transformer Purchases - Company	181005	0		0	Active	I
BFOE17	2016 Transformer Purchases-Company	161005	0		2.2	Closed 10/2017	I
BGBE17	2017 Transformer Purchases - Customer	171006	1,157.60	1,154.10	954.3	Active	C
BGBE18	Transformer Purchases - Customer O/H	181006	0		0	Active	C
BGCE17	2016 Transformer Purchases-Customer	161006	32.7		213.7	Closed 10/2017	C
BHBE17	2017 Meter Purchases - Company	171008	192.8	192.8	204	Active	M
BHBE18	Electric Meter - Company	181008	0		0	Active	M
BHOE17	2016 Meter Purchases-Company	161008	0		5.2	Closed 4/2017	M
BIBE17	2017 Meter Purchases - Customer	171007	426.9	426.9	409.4	Active	C
BIBE18	Electric Meter - Customer	181007	0		0	Active	C
BIOE17	2016 Meter Purchases-Customer	161007	0	315	-1.3	Closed 4/2017	C
		Sub-Totals:	5,459.00	11,364.60	5,424.70		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS ELECTRIC						
ECEE01	AMI Equipment, Unanticipated Replacements	171022	22.5	22.5	26.8	Active	O
ECEE02	2 way radio replacements	171014	5	5	0.6	Active	O
EECE01	Replace Seabrook Marsh RTU	13193	36.7	20.4	-4	Cancelled 9/2017	O
		Sub-Totals:	64.1	47.9	23.4		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS GENERAL						
ECOE01	Replace AMI Equipment	161025	0		0	Closed 12/2017	O
ECOE02	Two way radio replacements	161015	0	6	0	Closed 10/2017	O
ECOE03	Replace AMI SPU and Cell Modem	141034	0		0	Closed 12/2017	O
		Sub-Totals:	0	6	0		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	DISTRIBUTION ELECTRIC						
DABE00	Overhead Line Extensions - New Projects		70.1		39.7	Active	C
DABE02	Three Phase, Overhead Line Ext., Rocks Rd., Seabrook	171029	0		0	Closed 7/2017	
DABE03	Single Phase, Overhead Line Ext., 105 Hilldale Ave., South Hampton	171033	0	3.2	10.1	Closed 12/2017	
DABE04	Single Phase, O/H Line Ext., Lefevre Dr., Kingston	171041	0		7.9	Closed 12/2017	
DABE05	Single Phase, Overhead Line Ext., 129 Depot Rd, East Kingston	171044	0		8.9	Closed 12/2017	
DABE06	Three Phase, Overhead Line Ext., 180 Ashworth Ave., Hampton	171053	0	14.4	11.6	Closed 12/2017	
DABE07	Three Phase, O/H Line Ext., 1 Franklin St., Exeter	171055	0	6.3	3	Active	
DABE08	Single Phase, O/H Line Ext., 158 Epping Rd., Exeter	171061	0	19.6	10.2	Active	
DABE09	Single Phase, O/H Line Ext., 49 Heath St., Newton	171062	0	18.5	-2.6	Active	
DABE10	Single Phase, Overhead Line Ext., 53 Highland Rd., South Hampton	171063	0	6	-9.4	Active	
DACE00	Overhead Line Extensions, Carryover		15.1		0	Active	C
DBBE00	Underground Line Extensions - New Projects		313.4		261.1	Active	C
DBBE01	Three Phase, URD Line Ext., 40 Main St., Exeter	171025	0	19.8	66	Completed 12/2017	
DBBE02	Single Phase, URD Line Ext., 199 South Rd., Kensington	171026	0	11.1	-4.3	Active	
DBBE03	Single Phase, URD Line Ext., Rollins Farm Rd, Stratham - Phase 2	171027	0	25.5	-7.1	Active	
DBBE04	Three Phase, URD Line Ext., 8 Commerce Way, Exeter	171028	0	13.6	15	Closed 12/2017	
DBBE05	Three Phase, URD Line Ext., 147 Lafayette Rd., Seabrook	171031	0	23.6	20.3	Closed 12/2017	
DBBE06	Three Phase, URD Line Ext., 299 Exeter Rd., Hampton	171032	0	43	-3.9	Active	
DBBE07	Single Phase, URD Line Ext., Cowbell Crossing, Atkinson - Phase 4	171034	0	39.6	40.3	Closed 12/2017	
DBBE08	Three Phase, URD Line Ext., Exeter Rd., Hampton18X1	171035	0	32	33.5	Active	
DBBE09	Single Phase, URD Line Ext., Forrest St, Plaistow	171036	0	24.2	23.8	Closed 12/2017	
DBBE10	Single Phase, URD Line Ext., off Centennial St., Seabrook	171037	0	3.2	-3.2	Active	
DBBE11	Three Phase, URD Line Ext., Newfields Rd, Exeter	171038	0	23.9	-5.5	Active	
DBBE12	Single Phase, URD Line Ext., off Stratham Heights Rd., Stratham	171039	0	60.5	43.3	Completed 12/2017	
DBBE13	Three Phase, URD Line Ext., 23 Portsmouth Ave., Stratham	171040	0	14.5	15.6	Closed 12/2017	

Electric Category	2017
Growth	
Customer Additions (C)	2,577,900
Subtotal Growth	2,577,900
Non-Growth	
Reliability (R)	495,300
Maintenance Replacement (M)	4,527,500
Mandated (H)	632,000
System Improvement (I)	2,146,900
Grid Modernization (G)	0
Other (O)	372,500
Subtotal Non-Growth	8,174,200
Total	10,752,100

10,752,100
0

Budget Category	2017
Annual Requirements Blankets	
T&D Improvements	1,875,000
New Customer Additions	504,200
Outdoor Lighting	202,200
Emergency & Storm Restoration	681,800
Billable work	236,000
Transformers	1,308,200
Meters	617,300
Sub-Totals:	**5,424,700**
Distribution	
Overhead Line Extensions over $20,000	39,700
Underground Line Extensions over $20,000	457,900
Street Light Projects	-
Telephone Company Requests	618,100
Highway Projects	7,900
Distribution Pole Replacements	770,700
Specific Projects: Distribution	2,730,300
Sub-Totals:	**4,624,600**
Substation	
Specific Projects: Substation	589,600
Sub-Totals:	**589,600**
Communications	**23,400**
Tools, Shop, Garage	**64,500**
Laboratory	**12,400**
Office	**2,700**
Structures	**10,200**
Distribution Totals:	**10,752,100**

CONSTRUCTION BUDGET 2017 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DBBE14	Three Phase URD Line Ext., 21 Blossom Rd., Plaistow	171042	0	12	13.8	Closed 12/2017	
DBBE15	Single Phase, URD Line Ext., Wiggin Way, Stratham	171046	0	14.3	15.9	Completed 12/2017	
DBBE16	Three Phase, URD Line Ext., 29 Academy Ave., Hampton	171047	0	28.8	38.6	Active	
DBBE17	Three Phase, URD Line Ext., 22 Whittier St., Newton	171051	0	33.9	3.3	Active	
DBBE18	Single Phase, URD Line Ext., 97 Portsmouth Ave., Stratham	171052	0	26.1	-9	Active	
DBBE19	Three Phase, URD Line Ext., 277 Water St, Exeter	171054	0	31.5	-32	Active	
DBBE20	Single Phase, URD Line Ext., Osgood Rd., Kensington	171056	0	29.8	-7	Completed 10/2017	
DBBE21	Single Phase, URD Line Ext., Rollins Farm Rd., Stratham - Phase 3	171058	0	41	-16	Active	
DBBE44	Three Phase, URD Line Ext., 11 Plaistow Rd., Plaistow	171043	0	16.6	19.8	Closed 12/2017	
DBCE00	Underground Line Extensions, Carryovers		329.9		196.8	Active	C
DBCE01	Extend Three Phase, 4 Commerce Dr., Atkinson	161030	0		7.5	Closed 6/2017	
DBCE02	Installation of Secondary Underground Service, Drakeside Rd., Hampton	161038	0		3.9	Closed 4/2017	
DBCE03	Three Phase, URD Line Ext., 27 Brown Rd., Hampton Falls	161044	0	73.1	25.9	Active	
DBCE04	Three Phase, URD Line Ext., 80 Epping Rd, Exeter - Phase 1	161045	0	58.5	57	Closed 7/2017	
DBCE05	Three Phase, URD Line Ext., 9 Plaistow Rd., Plaistow	161047	0		0	Closed 1/2017	
DBCE06	Single Phase, URD Line Ext., 94 Black Snake Rd., Seabrook	151068	0	30	1.7	Closed 2/2017	
DBCE07	Three Phase, URD Line Ext., 12 Continental Dr., Exeter	161050	0		6.1	Closed 4/2017	
DBCE08	Single Phase, URD Line Ext., Chandler Ave, Plaistow - Phase 1	161055	0		6.1	Closed 2/2017	
DBCE09	Three Phase, URD Line Ext., 603 Lafayette Rd., Seabrook	161057	0		46.1	Closed 6/2017	
DBCE10	Single Phase, URD Line Ext., Folsom St., Exeter	161058	0		21.7	Closed 6/2017	
DBCE11	Remove O/H Secondary Lines, Install URD Line Ext., String Bridge, Exeter	161060	0		13.3	Closed 2/2017	
DBCE12	Single Phase, URD Line Ext., Sawmill Ridge, Atkinson, Phase 3	161061	0		7.6	Closed 4/2017	
DBCE20	Single Phase, URD Line Ext., off Sweet Hill Rd., Plaistow	151098	0		0	Closed 1/2017	
DCBE00	Street Light Projects		31			Active	M
DCCE00	Street Light Projects, Carryover		0			Active	M
DDBE00	Telephone Company Requests		0			Active	H
DDCE00	Telephone Requests, Carryover		408.5		618.1	Active	H
DDCE01	3353 Line Relocation, State Rt. 101, Hampton	141047	0	2,150.00	618.1	Active	
DEBE00	Highway Projects		143		7.9	Active	H
DEBE01	Town of Exeter - Relocate Poles for Bridge Construction, Rt. 108, Exeter	171059	0	50	7.9	Active	
Dec-00	Highway Projects, Carryover		0			Active	H
DEOE01	Relocation of Highway Light	141079	0		6	Closed 11/2017	H
DPBE01	Distribution Pole Replacement	171024	653.3	780	770.7	Active	M
DPBE02	Reconductor Water Street, Exeter	171030	104.9	175	134.3	Completed 12/2017	I
DPBE03	Circuit 19X3- Convert Newfields Rd, Exeter Waste Water Treatment Plant	171023	358.4	358.4	238.9	Active	I
DPBE04	Replace Primary Metering at Seabrook Nuke Plant	171060	52.1	213.7	52.2	Active	M
DPBE16	Distribution Pole Replacements (REP), Various Locations	161011	0		0	Closed 1/2017	M
DPBE18	Distribution Pole Replacements	181009	0		0	Active	M
DPCE01	Relocate Main Line to Route 111, Kingston/Danville - Circuit 22X1	161014	1,658.00	1,830.80	892.1	Active	I
DPCE02	Distribution Upgrades to Accommodate Foss Manufacturing, Hampton	161037	402.7	630	376.2	Active	I
DPCE03	Convert Exeter Road and Rebuild Brown Road to Three Phase, Hampton Falls Circuits 2X3 & 18X1	161034	112		82.7	Completed 3/2017	I
DPCE04	Replace the 03341 and the 3352 Reclosers at Wolf Hill	13161	0	154.6	19	Completed 1/2017	M
DPCE05	Upgrade Stard Road Tap	151066	11	230	7.8	Closed 12/2017	I
DPCE06	Replace Overhead Pole Line with Underground Facilities for PEA	161053	237.4		211.6	Completed 8/2017	I
DPNE01	Replace Failed Underground Cable, St. Magnus Condo's, Hampton	171050	0	113.7	113.6	Completed 3/2017	M
DPNE02	Wind Storm - March 2, 2017	171057	0	37.5	38.7	Active	M
DPOE03	Upgrade Neutral Along a Portion of Circuit 5H2, Plaistow	161056	0		61.9	Closed 6/2017	M
DPOE04	Replace H-Structure and Changeover	161059	0	39.4	0	Closed 3/2017	M
DRBE00	Reliabilty Projects		413.5		417.8	Active	R
DRBE01	Install Devices with Pulsefinding	171020	0	413.5	417.8	Completed 12/2017	
DRCE00	Replace manually operated switches with automated switches, 3343 and 3354 Lines		30.1		74.8	Active	R
DRCE01	Replace manually operated switches with automated switches, 3343 and 3354 Lines	151056	0	400.5	74.8	Completed 11/2017	
DRCE02	New Boston Road Tap - Install Reclosers	151043	0	302	0	Closed 12/2017	
DROE01	Install Motor Operated Air Breaks on 3362 & 3351 lines, RTU and SCADA	151058	0		2.7	Closed 12/2017	R
DROE03	Hampton S/S - Install Protective Devices on 3342, 3353 and 3348	13170	0	645.1	0	Closed 12/2017	R
		Sub-Totals:	5,344.70	9,322.70	4624.6		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE ELECTRIC						
EAEE01	Tools, Shop & Garage - Normal Additions and Replacements	171016	14	14	18.1	Active	O
EAEE02	Purchase and Replace Rubber Goods	171017	5.5	5.5	6	Active	O
EAEE03	Purchase and Replace Hot Line Tools	171018	3	3	5.7	Active	O
EAEE04	Normal Adds & Repl - Tools Meters & Services	171010	7	7	7.6	Completed 12/2017	O
EAEE05	Normal Additions and Replacement - Tools and Equipment Substation	171021	7	7	8.6	Active	O
EAEE06	Purchase/Replace Tools for Bucket Truck #28	171019	6.5	6.5	0.5	Active	O
		Sub-Totals:	43	43	46.5		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE GENERAL						
EAOE02	Tools, Shop & Garage - Normal Additons and Replacements	161017	0		0	Closed 7/2017	O
EAOE03	Purchase and Replace Rubber Goods	161018	0		0.3	Closed 6/2017	O
EAOE04	Normal additions & replacement - tools & equipment Meter and Services	161012	0	7	0	Cancelled 7/2017	O
EAOE05	Purchase and Replace Hot Line Tools	161019	0		2	Closed 7/2017	O
EAOE06	Purchase/Replace Tooling for Bucket Truck #23	161020	0		6.5	Closed 7/2017	O
EAOE07	Normal Replacements Tools - Substation	161024	0		0.4	Closed 2/2017	O
EAOE08	Replace Tooling for Bucket Truck #33 - Damaged in Fire	161029	0		8.8	Closed 7/2017	O

Electric Category	2017

Budget Category

CONSTRUCTION BUDGET 2017 UES Seacoast

12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
		Sub-Totals:	0	7	18		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	LABORATORY GENERAL						
EBBE01	This covers unscheduled additions and replacements of lab instruments, test equipment, etc	171011	7	7	11.5	Completed 12/2017	O
EBOE01	Lab Equipment normal additions and replacements	161027	0		0.9	Completed 1/2017	O
		Sub-Totals:	7	7	12.4		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE ELECTRIC						
EDEE01	Office Furniture and Equipment	171015	3.5	3.5	2.7	Active	O
		Sub-Totals:	3.5	3.5	2.7		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE GENERAL						
EDOE01	Office Furniture and Equipment-Replacements	161022	0		0	Closed 3/2017	O
		Sub-Totals:	0	0	0		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	STRUCTURES GENERAL						
GPBE01	Normal Improvements to Kensington Facility	171013	13.5	13.5	8.9	Active	O
GPCE01	Electric system/life safety upgrades	13146	40	51.6	1.3	Active	O
GPOE01	Normal Improvements to Seacoast Facility	161013	0		0	Closed 7/2017	O
		Sub-Totals:	53.5	65.1	10.2		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	SUBSTATION ELECTRIC						
SPCE01	Guinea 18X1 - Replace Breaker and Relaying	161052	237.1	237.9	259.3	Closed 12/2017	O
SPNE01	Replace 19X3 Recloser	171012	0	180	179.5	Completed 11/2017	M
SPNE02	Replace Failed Insulators and Station Service Transformers	171048	0	91	87.7	Closed 12/2017	M
SPOE01	Kingston Substation-System Supply	13184	0		42.5	Closed 11/2017	I
SPOE02	Build New 5X3 Distribution Circuit Position in Plaistow Substation	151076	0	556.1	20.6	Closed 12/2017	I
		Sub-Totals:	237.1	1,065.00	589.6		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TRANSPORTATION ELECTRIC						
FEBE01	Replace Pickup Truck #18		0			Active	
FEBE02	Replace Pick up Truck #15		0			Active	
FEBE03	Replace Bucket Truck #28		0			Active	
FEBE04	Replace wire trailer		0			Active	
		Sub-Totals:	0	0			
		Grand Totals:	11,211.90	21,931.70	10,752.1		

Electric Category	2017

Budget Category

CONSTRUCTION BUDGET 2018 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	BLANKETS ELECTRIC						
BABC18	Electric T&D Improvements	180100	1,294.60	1,294.60	1,425.00	Active	M
BABC19	Electric T&D Improvements	190100	0		0	Active	M
BACC18	Electric T & D Improvements	170100	32.9	1,188.00	-68.7	Completed 12/2018	M
BAOC16	T & D Improvements	140100	0		0	Closed 1/2018	M
BAOC17	2015 Electric T & D	150100	0	1,225.00	-1.8	Closed 1/2018	M
BAOC18	Electric T&D Improvements	160100	0	1,138.20	42.7	Closed 2/2018	M
BBBC18	New Customer Additions	180101	367	375.5	476.1	Active	C
BBBC19	New Customer Additions	190101	0		0	Active	C
BBCC18	New Customer Additions	170101	42	420	36.4	Completed 12/2018	C
BBOC18	New Customer Additions	160101	0	294.9	-9.5	Closed 8/2018	C
BCBC18	Outdoor Lighting	180102	127.4	127.4	129.4	Active	M
BCBC19	Outdoor Lighting	190102	0		0	Active	M
BCCC18	Outdoor Lighting	170102	5.4	106.2	2.1	Completed 3/2018	M
BCOC18	Outdoor Lighting	160102	0	143.6	-2.7	Closed 2/2018	M
BDBC18	Emergency & Storm Restoration	180103	821	821	1,164.20	Active	M
BDBC19	Emergency & Storm Restoration	190103	0		0	Active	M
BDCC18	Emergency & Storm Restoration	170103	14.5	753	-655	Completed 10/2018	M
BDOC17	2015 Emergency & Storm	150103	0	574.3	-1.1	Closed 2/2018	M
BDOC18	Emergency & Storm Restoration	160103	0	500	-53.2	Closed 2/2018	M
BEBC01	5 Quincy Rd Concord-Installation of a Pad & wire for Subdiv lot	170143	0		0	Closed 2/2018	M
BEBC18	Billable Work	180104	257.7	257.7	282.6	Active	M
BEBC19	Billable Work	190104	0		0	Active	M
BECC18	Billable Work	170104	10.6	295	9.5	Completed 12/2018	M
BEOC17	2015 Billable Work	150104	0	281.8	-3.2	Closed 5/2018	M
BEOC18	Billable Work	160104	0	285	-5	Closed 11/2018	M
BFBC18	Transformer Purchases - Company Conversions	180105	81.7	51	1.7	Active	I
BFBC19	Transformer Purchases - Company	190105	0		0	Active	I
BFCC18	2017 Transformer Purchases - Company	170105	0		25.1	Closed 8/2018	I
BGBC18	Transformer Purchases - Customer Requirements	180106	728.4	894	1,426.50	Active	C
BGBC19	Transformer Purchases - Customer	190106	0		0	Active	C
BGCC18	2017 Transformer Purchases - Customer	170106	15.9		1.5	Closed 8/2018	C
BHBC18	Electric Meter Purchases - Company	180108	174.1	174.1	161.6	Active	M
BHBC19	Electric Meter Purchases - Company	190108	0		0	Active	M
BHOC18	2017 Meter Purchases - Company	170108	0		1.2	Closed 8/2018	M
BIBC18	Electric Meter Purchases - Customers	180107	409.8	409.8	415.5	Active	C
BIBC19	Electric Meter Purchases - Customers	190107	0		0	Active	C
BIOC18	2017 Meter Purchases - Customer	170107	0		0	Closed 8/2018	C
		Sub-Totals:	4,383.10	11,610.10	4,800.90		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS ELECTRIC						
ECEC01	Two Way Radio Replacements	180125	3	3	2.7	Active	O
ECEC02	Purchase Radio Recording System	180136	26	26	19.5	Closed 11/2018	O
		Sub-Totals:	29	29	22.2		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS GENERAL						
ECNC01	2018 IT Infrastructure	180120	0	173.5	36.7	Active	O
ECNC02	2018 Interface Enhancements	180132	0	216	157	Active	O
ECNC03	2018 Customer Facing Enhancements	180133	0	280.5	194.5	Active	O
ECNC04	2018 MeterSense Enhancements	180134	0	114	48.2	Active	O
ECNC05	Move e-Intake estimating functionality into GEM	180139	0	30.6	20.2	Active	O
ECNC06	Dev / Staging Refresh	180140	0	13.9	0	Active	O
ECNC07	Legacy Interface Job Rewrite	180141	0	5	3.5	Active	O
ECNC08	WebOps Replacement - Year 1 of 3	180142	0	21.2	26.4	Active	O
ECNC09	General Software Enhancements - 2018	180143	0	19.8	24	Active	O
ECNC10	TESS Replacement	180144	0	8.9	0	Active	O
ECNC11	2018 Cyber Security Enhancements	180146	0	45.6	7.2	Active	O
ECNC12	OMS Regulatory Reports - Carry-over	180147	0	27.5	6.6	Active	O
ECNC13	AMI Command Center Version Upgrade 7.XX	180152	0		9.7	Closed 11/2018	O
ECNC14	Microsoft Exchange Upgrade Carry-Over	180160	0	8.7	4.4	Active	O
ECNC15	Electronic Time Sheet-Phase Two	180162	0	28.1	20.8	Active	O
ECNC16	Universal Payment System (UPS) Reporting	180164	0	4.5	0	Active	O
ECNC72	Microsoft Exchange Upgrade 2007 to 2016	170176	0		0	Closed 8/2018	O
ECOC01	Two Way Radio Replacements	170114	0		0	Closed 5/2018	O
ECOC02	AMI Equipment, Unanticipated Replacements	170123	0		0	Closed 5/2018	O
ECOC03	Meter data archiving plan	170127	0		0.7	Closed 11/2018	O
ECOC04	Replace MV-90 communication bank modules	170128	0	6.7	0	Cancelled 9/2018	O
ECOC05	AMI Command Center Version Upgrade 6.5	170129	0		0	Cancelled 1/2018	O
ECOC06	GIS Version Upgrade & Data Model Consolidation	150129	0	94.4	17.3	Active	O
ECOC07	Upgrade Generator Interconnection Database	140141	0	56	0.6	Active	O
ECOC08	2017 Cyber Security Scheduled Replacements	170131	0		-0.8	Closed 5/2018	O
ECOC09	2017 IT Infrastructure	170136	0		2.3	Closed 5/2018	O
ECOC10	Electric Inspections Version Upgrade	170151	0	38	0	Cancelled 11/2018	O

Electric Category	2018
Growth	
Customer Additions (C)	2,765,400
Subtotal Growth	2,765,400
Non-Growth	
Reliability (R)	252,800
Maintenance Replacement (M)	4,110,500
Mandated (H)	55,000
System Improvement (I)	-394,100
Grid Modernization (G)	0
Other (O)	1,158,400
Subtotal Non-Growth	5,182,600
Total	7,948,000
	7,948,000
	0

Budget Category	2018
Annual Requirements Blankets	**2018**
T&D Improvements	1,397,200
New Customer Additions	503,000
Outdoor Lighting	128,800
Emergency & Storm Restoration	454,900
Billable work	283,900
Transformers	1,454,800
Meters	578,300
Sub-Totals:	**4,800,900**
Distribution	
Overhead Line Extensions over $20,000	97,300
Underground Line Extensions over $20,000	321,600
Street Light Projects	-
Telephone Company Requests	(4,000)
Highway Projects	59,000
Distribution Pole Replacements	868,000
Specific Projects: Distribution	575,200
Sub-Totals:	**1,917,100**
Substation	
Specific Projects: Substation	373,200
Sub-Totals:	**373,200**
Communications	**637,700**
Tools, Shop, Garage	**55,700**
Laboratory	**5,800**
Office	**7,700**
Structures	**149,900**
Distribution Totals:	**7,948,000**

CONSTRUCTION BUDGET 2018 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
ECOC11	2017 General Software Enhancements	170157	0		8.9	Closed 10/2018	O
ECOC12	Eintake Miigration	170171	0		15.7	Closed 8/2018	O
ECOC13	IS Project Tracker Replacement	170172	0	9.9	7.2	Active	O
ECOC14	24 Hour Damage Assessment/Field Restoration	140146	0		0	Closed 4/2018	O
ECOC15	Electronic Time Sheet-Phase One	170130	0		4.4	Closed 8/2018	O
ECOC20	First Responder - Municipal Trouble Reporting App	160133	0	118.8	0	Closed 1/2018	O
		Sub-Totals:	0	1,321.60	615.5		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	DISTRIBUTION ELECTRIC						
DABC00	Overhead Line Extensions		67.9		92.2	Active	C
DABC01	Single Phase, O/H Line Ext., Gauthier Dr., Epsom	180117	0		70.6	Closed 11/2018	
DABC02	Three Phase, Temporary O/H Line Ext., 123 Pleasant St., Concord	180126	0	51.1	-0.4	Completed 5/2018	
DABC03	Single Phase, O/H Line Ext., Black Hall Rd , Epsom	180165	0		8.7	Closed 11/2018	
DABC04	Single phase, OH line ext 228 Center Rd. Salisbury - Non-Billable	180175	0	12	35.7	Active	
DABC05	Three phase OH Primary Silver Hills Dr Pembroke	180177	0	6.1	-8.4	Active	
DABC06	Single Phase, O/H Line Extension. High St. Boscawen-Billable	180189	0	23.5	-14	Active	
DACC00	Overhead Line Extensions - Carryover		11.8		5.1	Completed 4/2018	C
DACC02	5 Pleasant View Ave-One P OH Line Ext	160155	0		0	Closed 1/2018	
DACC03	8 Gordon Rd Bow-3ph OH line Ext-Billable	170165	0	4.1	5.1	Closed 12/2018	
DACC04	283 Shaker Rd Concord-One Pole Line Ext-Billable	160167	0		0	Closed 1/2018	
DACC05	53 South Bow Rd-OH Line Extension -Billable	160168	0		0	Closed 1/2018	
DAOC03	75 New Rd Canterbury-2 Pole OH Line Ext-Billable	160125	0	6.2	0	Closed 1/2018	C
DBBC00	Underground Line Extensions		154.1		194	Active	C
DBBC01	79 Dow Rd., Bow - Relocate Riser Pole	180109	0		54	Closed 8/2018	
DBBC02	Single Phase, URD Line Ext., Hoit Rd, Concord	180145	0	28.1	22.8	Active	
DBBC03	Single Phase, URD Line Ext., 131 West Parish Rd., Concord	180148	0	9.3	7.7	Completed 11/2018	
DBBC04	Single Phase, URD Line Ext., Tuscany Village, Riesling Terrace, Penacook	180157	0	28.9	-5.9	Active	
DBBC05	Single Phase, URD Line Ext. - Billable	180158	0		16.2	Closed 11/2018	
DBBC06	Single Phase, URD Line to Two Pad Mounts, High Meadows, 6 Dunbarton Rd., Bow	180159	0		0	Completed 11/2018	
DBBC07	Three Phase, URD Line Ext., 250 Pleasant St., Concord	180167	0	32.6	-3.4	Active	
DBBC08	Three Phase, URD Line Ext., 285-287 Loudon Rd., Concord	180169	0	26.5	-5.9	Active	
DBBC09	Three Phase, URD Line Ext., 289 Loudon Rd., Concord	180170	0	30.7	27.6	Closed 12/2018	
DBBC10	Single Phase, URD Line Ext., Mountain Rd., Concord	180173	0	16.1	14.9	Closed 12/2018	
DBBC11	Three Phase, URD Line Ext., 660 River Rd., Bow - Non Billable	180174	0	24.3	31.2	Completed 12/2018	
DBBC12	Single phase, URD LIne Extens. 33 Elkins Rd, Epsom	180176	0		8.3	Active	
DBBC13	Single Phase URD Primary Line Ext. Fawn Court Bow Non-Billable	180179	0	24.6	-2.4	Active	
DBBC14	Single phase URD Line Ext. Oxbow Bluff -Penacook -Billable	180180	0	28.6	-10.1	Active	
DBBC15	Three Phase URD Line Ext -77 Merrimack St. Penacook-Non Billable	180182	0	21.5	28	Closed 1/2018	
DBBC16	Three Phase URD Line Ext 5-7 S State St. Concord-Non Billable	180183	0	63.8	10.9	Active	
DBCC00	Underground Line Extensions, Carryover		17.1		127.6	Active	C
DBCC01	7 Penacook St Penacook-Wasterwater Treatment Plant-Billable	160127	0		0	Closed 1/2018	
DBCC02	Tremont St Boscawen-California Fields-Primary urd line ext-Billable	160128	0	46.4	-7.5	Closed 12/2018	
DBCC03	The Woods of Bow Dev-Parson's Way Ph III-compl urd line ext-Billable	170146	0		6.8	Closed 5/2018	
DBCC04	1113 Route 3A Bow-RYKEL Complex-PrimaryURD Line Ext	170138	0	18.4	20.7	Closed 12/2018	
DBCC05	Vintage Estates, Sonoma Way Concord-singl ph urd line ext	170156	0	47	4.9	Active	
DBCC06	State of NH Liquor Commission 50 Storrs St-3 ph Line Ext-Billable	160143	0		-13.6	Closed 12/2018	
DBCC07	6 Dunbarton Center Rd Bow-High Meadows-prim urd to two pads-billable	170162	0	38.4	40.1	Closed 12/2018	
DBCC08	163 N State St Merrimack County Court Primary Extend urd to pad	170169	0	20.2	38.8	Closed 12/2018	
DBCC09	250 Pleasant St-Concord Hospital Memorial Bld-3 PH Primary urd to 3 ph transf	170170	0		0.7	Closed 9/2018	
DBCC10	76 Mountain Rd Epsom Getaway House-OH & URD Primary Line Extension-billable	170173	0	25.9	-13.9	Closed 12/2018	
DBCC11	225 Water St Boscawen-OH to URD primary line ext-Non-Billable	170175	0		17.2	Closed 5/2018	
DBCC12	Sunrise Meadows Senior Housing-Short Falls Rd Epsom urd line ext	170153	0	33	33.3	Active	
DCBC00	Street Light Projects		5.2			Active	M
DCCC00	Street Light Projects - Carryover		5.4			Completed 2/2018	M
DDBC00	Telephone Company Requests		22			Active	H
DDCC00	Telephone Company Request - Carryover		2		-4	Completed 2/2018	H
DDCC01	Dunbarton Tel Requested Multiple Pole Replacements	170137	0		-4	Closed 5/2018	
DEBC00	Highway Projects		100.1		74.8	Active	H
DEBC01	Manor & Abbott Road, Concord - Roundabout	180154	0	93.5	74.8	Closed 10/2018	
DECC00	Highway Projects, Carryover		0		-15.8	Completed 8/2018	H
DECC01	TIGER Main Street Project-Pleasant St to Thompson St Concord	160141	0		0	Closed 1/2018	
DECC02	1 Knox Rd Bow-Bow Safety Complex-Relocate Primary-Billable	160162	0		-15.8	Closed 11/2018	
DECC03	CIP29 Exit 16 Roundabout - Concord	170140	0		0	Closed 5/2018	
DECC04	Pole Relocations for Bridge Replacement Over White Brook	170164	0		0	Closed 11/2018	
DEOC01	Sewalls Falls Bridge-Relocate Pole Line	150173	0		0	Closed 1/2018	H
DPBC01	Condemned Poles Distribution	190112	779.5		865.1	Closed 12/2018	M

Electric Category	2018

Budget Category

CONSTRUCTION BUDGET 2018 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DPBC02	Replace Man Hole roof with new precast roof	180181	239.4	277.4	50.8	Active	M
DPBC03	Rebuild Low Ave, Concord with Hendrix Construction	180172	102.7	102.7	56.1	Active	M
DPBC04	Replace Direct Burried cable with conduit and 35kv URD Cable	180171	97.2	129.3	126.1	Completed 12/2018	M
DPNC01	Primary Net Metering for the Hydro Dam	180156	0	101.5	10.2	Completed 12/2018	M
DPNC02	May 4th Wind Event	180185	0	130.9	0	Active	M
DPNC03	Wind Event 7-10-18	180187	0	124	0	Active	M
DPNC04	Replace Failed URD Primary Cable and add Pull Box	180188	0	27.2	27.2	Active	M
DPOC01	Condemned Poles quarter one 2017	170115	0	735.1	2.9	Closed 5/2018	M
DPOC02	Replace Chimney and riser	170168	0		0	Closed 12/2018	M
DPOC03	Replaced Failed Primary Cable - Portsmouth St., Concord	170152	0		52	Closed 5/2018	M
DPOC04	New Subtransmission Lines - Broken Ground to Hollis	160158	0		0	Closed 5/2018	I
DRBC00	Reliability Projects		262.7		118	Active	R
DRBC10	Substation Reliability Enhancements at West Concord	180153	0	126	49	Completed 11/2018	
DRBC12	Install Recloser - Pole 60 - Bow Bog Rd., Bow	180163	0	108.8	69	Active	
DROC13	Substation Reliability Improvements at Penacook	170166	0	202.5	134.8	Closed 11/2018	R
DROC15	Install 430 ft of conduit and 1/0 Al 35KV URD cable	170155	0	53.8	0	Closed 9/2018	R
		Sub-Totals:	1,867.00	2,879.90	1917.1		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE ELECTRIC						
EAEC01	Tools, Shop and Garage, Normal additions and replacements	190113	14		19.2	Closed 12/2018	O
EAEC02	Purchase and Replace Rubber Goods	180128	5.5	5.5	4.2	Active	O
EAEC03	Purchase and Replace Hot Line Tools	180129	3.5	3.5	4.5	Closed 12/2018	O
EAEC04	Normal additions & replacement - tools & equipment Metering	180111	7	7	1.4	Active	O
EAEC05	Purchase new Dig safe locating machine	180150	4.2		3.8	Closed 11/2018	O
EAEC06	Normal Additions and Replacements - Tools and Equipment - Substation	180135	8.5	8.5	8	Active	O
EAEC07	Purchase Bierer ST-800 Service tester	180130	1.4		1.4	Closed 11/2018	O
EAEC08	Purchase Milwaukee battery operated 6 ton crimper	180131	2.8		3.6	Closed 11/2018	O
		Sub-Totals:	46.9	24.5	46.1		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE GENERAL						
EACC01	Purchase tools for new Digger truck # 30	180155	5	5	3.1	Active	O
EAOC01	Tools, Shop & Garage - Normal Additions and Replacements	170116	0	13.5	0.8	Closed 10/2018	O
EAOC02	Purchase and Replace Rubber Goods	170117	0	5.5	0.3	Closed 8/2018	O
EAOC03	Purchase and Replace Hot Line Tools	170118	0	3.3	0	Closed 10/2018	O
EAOC04	The normal addition and replacement of tools and equipment for the Electric Meter Department.	170110	0		0	Closed 8/2018	O
EAOC05	Normal additions & replacement - tools & equipment Substation	170122	0		0.3	Closed 8/2018	O
EAOC06	Purchase tools for new Bucket Truck # 23	170167	0	5	5.1	Closed 9/2018	O
EAOC08	Purchase Non-Entry Manhole rescue system	160131	0		0	Closed 8/2018	O
		Sub-Totals:	5	32.3	9.6		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	LABORATORY GENERAL						
EBBC01	Lab Equipment - Normal Additions and Replacements	180112	7	7	5.8	Active	O
EBOC01	Unscheduled Additions & Replacements Lab Instruments	170111	0		0	Closed 8/2018	O
		Sub-Totals:	7	7	5.8		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE ELECTRIC						
EDEC01	Office Furniture and Equipment	180116	3.5	3.5	7.5	Active	O
		Sub-Totals:	3.5	3.5	7.5		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE GENERAL						
EDOC01	Office Furniture & Additions - Normal Additions & Replacements	170120	0		0.2	Closed 8/2018	O
		Sub-Totals:	0	0	0.2		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	STRUCTURES GENERAL						
GPBC01	Normal Improvements to Capital Facility	180119	15	15	11.7	Active	O
GPBC03	Physical Security Improvements	180121	12	12	3.1	Active	O
GPBC04	Office & Systems Furniture Reconfigurations	180122	100	100	135.1	Active	O
GPOC01	Normal Improvement Capital DOC	170113	0		0	Closed 8/2018	O
GPOC02	Replace Roof at Capital DOC	170135	0		0	Closed 5/2018	O
GPOC03	CAPITAL - Relocate SCADA Equipment	13248	0		0	Closed 8/2018	O
GPOC04	Electrical systems and life safety upgrades	13243	0		0	Closed 8/2018	O
		Sub-Totals:	127	127	149.9		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	SUBSTATION ELECTRIC						
SPBC01	Replace the 374J5 and the 374J6 Switches	190114	27.2		21.8	Closed 11/2018	M
SPBC02	Bridge Street - Replace 35KV Line Relaying & Modify RTU	180149	361	672.2	228.7	Active	O

Electric Category	2018

Budget Category

CONSTRUCTION BUDGET 2018 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
SPCC01	Replaced Failed 2H1 Recloser	170142	237.4		314.2	Closed 11/2018	M
SPNC01	Install 2nd AMI TCU at Penacook	180138	0	80.2	77.6	Completed 11/2018	O
SPNC02	Replace 2H4 Regulators	180151	0		59.9	Closed 11/2018	M
SPNC03	Replace Failed 13W1 Recloser	180161	0	106.5	83.7	Closed 11/2018	M
SPOC01	Install Stone in Substation	170126	0		-4.7	Closed 11/2018	O
SPOC02	Landgon S/S - Replace 374J5 & 375J6	170125	0	64.4	0	Cancelled 1/2018	M
SPOC03	Broken Ground - Site Evaluation, Permitting, Preliminary Survey	140144	0	12,620.00	-500.4	Active	I
SPOC04	Hollis S/s - Upgrades to Accomodate Broken Ground	160159	0		79.5	Closed 8/2018	I
SPOC05	Replace Failed Operating Mechanism on the 13W1 Recloser	170161	0		9.8	Closed 8/2018	M
SPOC06	Replace 35kV Bushings on 3T1 at Gulf St S/S	170174	0		3.1	Closed 8/2018	M
		Sub-Totals:	625.5	13,543.30	373.2		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TRANSPORTATION ELECTRIC						
FEBC01	Replace Digger Truck - #30		0			Active	
FEBC02	Replace Pickup Truck - #55/Standby		0			Active	
FEBC03	Replace Pole Trailer - #T12		0			Active	
FEBC04	Replace Pickup Truck - #6/Digsafe		0			Active	
		Sub-Totals:	0	0			
		Grand Totals:	7,094.00	29,578.20	7,948.0		

Electric Category	2018

Budget Category

CONSTRUCTION BUDGET 2018 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	BLANKETS ELECTRIC						
BABE18	Electric T&D Improvements	181000	1,830.20	1,806.60	1,603.60	Active	M
BABE19	Electric T & D Improvements	191000	0		0	Active	M
BACE18	Electric T & D Improvements	171000	52.7	1,955.00	25.6	Active	M
BAOE17	2015 Electric T&D	151000	0	1,507.20	-12.9	Closed	M
BAOE18	Electric T&D Improvements	161000	0	1,556.70	-3.2	Completed	M
BBBE18	NewCustomer Additions	181001	599	575.2	533.3	Active	C
BBBE19	New Customer Additions	191001	0		-0.6	Active	C
BBCE18	New Customer Additions	171001	10.5	559.4	28.9	Active	C
BBOE18	New Customer Additons	161001	0	526.6	-0.3	Closed	C
BCBE18	Outdoor Lighting	181002	317.9	240.6	158.7	Active	M
BCBE19	Outdoor Lighting	191002	0		0	Active	M
BCCE18	Outdoor Lighting	171002	8.7	276.8	8.5	Active	M
BCOE18	Outdoor Lighting	161002	0	274.6	-0.3	Completed	M
BDBE18	Emergency & Storm Restoration	181003	495	495	867	Active	M
BDBE19	Emergency & Storm Restoration	191003	0		0	Active	M
BDCE18	Emergency & Storm Restoration	171003	19.4	575.2	-100.6	Active	M
BDOE18	Emergency & Storm Restoration	161003	0	396.9	-0.7	Completed	M
BEBE18	Billable Work	181004	410.2	410.6	355.7	Active	M
BEBE19	Billable Work	191004	0		-1.6	Active	M
BECE18	Billable Work	171004	0	410.1	-29.5	Active	M
BEOE17	2015 Billable Work	151004	0	390.1	0	Closed	M
BEOE18	Billable Work	161004	0	399.7	-17.3	Completed	M
BFBE18	Transformer Purchases - Company	181005	859.8	859.8	766.1	Active	I
BFBE19	Transformer Purchases - Company	191005	0		0	Active	I
BFCE18	2017 Transformer Purchases - Company	171005	0		0	Active	I
BGBE18	Transformer Purchases - Customer O/H	181006	1,219.80	1,320.70	1,321.60	Active	C
BGBE19	Transformer Purchases - Customer	191006	0		0	Active	C
BGCE18	2017 Transformer Purchases - Customer	171006	45.3		205.9	Active	C
BHBE18	Electric Meter - Company	181008	305.1	305.1	265.4	Active	M
BHBE19	Electric Meter - Company	191008	0		0	Active	M
BHOE18	2017 Meter Purchases - Company	171008	0		1	Closed	M
BIBE18	Electric Meter - Customer	181007	447.3	447.3	507.6	Active	C
BIBE19	Electric Meter - Customer	191007	0		0	Active	C
BIOE18	2017 Meter Purchases - Customer	171007	0		49.1	Closed	C
		Sub-Totals:	6,620.70	15,289.20	6,531.00		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS ELECTRIC						
ECEE01	Radio Replacement Project	181022	197	222	199	Active	O
ECEE02	Two Way Radio Replacements		4			Active	O
		Sub-Totals:	201	222	199		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS GENERAL						
ECOE01	AMI Equipment, Unanticipated Replacements	171022	0		0	Closed	O
ECOE02	2 way radio replacements	171014	0		0	Closed	O
		Sub-Totals:	0	0	0		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	DISTRIBUTION ELECTRIC						
DABE00	Overhead Line Extensions - New Projects		71		4.4	Active	C
DABE01	Relocation of Pole, Three Phase Service, 92 Ashworth Ave., Hampton	181012	0	5.3	14.1	Completed	
DABE02	Single Phase, Overhead Line Ext., 26 Moulton Ridge Rd., Kensington	181049	0	5.4	6.5	Active	
DABE03	Single Phase, O/H Line Ext., Bent Grass Circle, Kingston	181065	0	9.4	12.7	Completed	
DABE04	Three Phase, O/H Line Ext., 137 Folly Mill Rd., Seabrook - Building B	181067	0	4.1	-5	Active	
DABE05	Three Phase, O/H Line Ext., Off Rocks Rd., Seabrook - A Lot	181070	0		-23.9	Active	
DACE00	Overhead Line Extensions, Carryover		10.3		49.9	Active	C
DACE01	Three Phase, O/H Line Ext., 1 Franklin St., Exeter	171055	0		4.7	Closed	
DACE02	Single Phase, O/H Line Ext., 158 Epping Rd., Exeter	171061	0		10.6	Closed	
DACE03	Single Phase, O/H Line Ext., 49 Heath St., Newton	171062	0		19.4	Closed	
DACE04	Single Phase, Overhead Line Ext., 53 Highland Rd., South Hampton	171063	0	6	15.2	Closed	
DBBE00	Underground Line Extensions - New Projects		373.7		154.6	Active	C
DBBE02	Three Phase, URD Line Ext., 4 Puzzle Ln., Newton	181021	0		8.6	Closed	
DBBE03	Single Phase and Three Phase, URD Line Ext., off Main St., Atkinson	181029	0	174.1	89.9	Active	
DBBE04	Three Phase, URD Line Ext., Country Club Dr., Atkinson	181031	0	119.5	154.8	Active	
DBBE05	Single Phase, URD Line Ext., Willowbrook Ave., Stratham	181032	0	22.3	28.7	Completed	
DBBE06	Three Phase, URD Line Ext., 3 Meeting Place Dr., Exeter	181033	0	4.2	2.3	Closed	
DBBE09	Single Phase, URD Line Ext., 24 Old Stage Rd., Hampton Falls	181036	0	9.9	7	Closed	

Electric Category	2018
Growth	
Customer Additions (C)	3,158,600
Subtotal Growth	3,158,600
Non-Growth	
Reliability (R)	487,200
Maintenance Replacement (M)	4,507,100
Mandated (H)	527,400
System Improvement (I)	1,362,000
Grid Modernization (G)	0
Other (O)	296,800
Subtotal Non-Growth	7,180,500
Total	10,339,100
	10,339,100
	0

Budget Category	
Annual Requirements Blankets	**2018**
T&D Improvements	1,613,100
New Customer Additions	561,300
Outdoor Lighting	166,900
Emergency & Storm Restoration	765,700
Billable work	307,300
Transformers	2,293,600
Meters	823,100
Sub-Totals:	**6,531,000**
Distribution	
Overhead Line Extensions over $20,000	54,300
Underground Line Extensions over $20,000	458,800
Street Light Projects	-
Telephone Company Requests	271,200
Highway Projects	256,200
Distribution Pole Replacements	746,000
Specific Projects: Distribution	1,502,000
Sub-Totals:	**3,288,500**
Substation	
Specific Projects: Substation	240,800
Sub-Totals:	**240,800**
Communications	**199,000**
Tools, Shop, Garage	**58,900**
Laboratory	**6,000**
Office	**2,300**
Structures	**12,600**
Distribution Totals:	**10,339,100**

CONSTRUCTION BUDGET 2018 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DBBE13	Three Phase, URD Line Ext., Mill Rd., Hampton	181040	0	6.2	-52.2	Active	
DBBE14	Three Phase, URD Line Ext., 118 Portsmouth Ave., Stratham	181048	0	22.7	23.6	Completed	
DBBE15	Single Phase, URD Line Ext., McCarron Dr., Hampton	181038	0	7.8	5.2	Completed	
DBBE17	Three Phase, URD Line Ext., 137 Folly Mill Rd., Seabrook - Building A	181066	0	9.3	-11.5	Active	
DBBE18	Three Phase, URD Line Ext., 183 Epping Rd, Exeter	181059	0	68.9	-50.1	Active	
DBBE20	Single Phase, URD Line Ext., 8 Kingston Rd, Exeter	181069	0	14.3	-12.1	Active	
DBBE22	Three Phase, URD Line Ext, Main St., Kingston	181041	0	36.3	-30.4	Active	
DBBE23	Single Phase, URD Line Ext., 460 East Rd., Hampstead	181044	0	12.8	1.6	Completed	
DBBE24	Single Phase, URD Line Ext., 199 South Rd, Kensington	181071	0		-24.4	Active	
DBBE25	Single Phase, URD Line Ext., Whittaker Way, Stratham	181068	0	22	-6.3	Active	
DBBE30	Single Phase, URD Line Ext., off Stratham Ln, Stratham	181043	0	17.5	19.7	Closed	
DBCE00	Underground Line Extensions, Carryovers		270.3		304.2	Active	C
DBCE01	Three Phase, URD Line Ext., 40 Main St., Exeter	171025	0		-33.7	Closed	
DBCE02	Single Phase, URD Line Ext., 199 South Rd., Kensington	171026	0	11.1	0	Active	
DBCE03	Single Phase, URD Line Ext., Rollins Farm Rd, Stratham - Phase 2	171027	0	25.5	30.7	Closed	
DBCE04	Three Phase, URD Line Ext., 299 Exeter Rd., Hampton	171032	0		55.6	Closed	
DBCE05	Single Phase, URD Line Ext., Cowbell Crossing, Atkinson - Phase 4	171034	0		9.3	Closed	
DBCE06	Three Phase, URD Line Ext., Exeter Rd., Hampton18X1	171035	0	32	-5.5	Closed	
DBCE07	Single Phase, URD Line Ext., off Centennial St., Seabrook	171037	0		10	Closed	
DBCE08	Three Phase, URD Line Ext., Newfields Rd, Exeter	171038	0		34	Closed	
DBCE09	Single Phase, URD Line Ext., off Stratham Heights Rd., Stratham	171039	0		3.8	Closed	
DBCE10	Three Phase, URD Line Ext., 29 Academy Ave., Hampton	171047	0	28.8	-4.9	Closed	
DBCE11	Three Phase, URD Line Ext., 22 Whittier St., Newton	171051	0		21	Closed	
DBCE12	Single Phase, URD Line Ext., 97 Portsmouth Ave., Stratham	171052	0		33.4	Closed	
DBCE13	Three Phase, URD Line Ext., 277 Water St, Exeter	171054	0	31.5	55.4	Active	
DBCE14	Single Phase, URD Line Ext., Osgood Rd., Kensington	171056	0		28.7	Closed	
DBCE15	Single Phase, URD Line Ext., Rollins Farm Rd., Stratham - Phase 3	171058	0	41	63.8	Closed	
DBCE16	Three Phase, URD Line Ext., 27 Brown Rd., Hampton Falls	161044	0		8.2	Closed	
DBCE17	Three Phas, URD Line Ext. 105 Towle Farm Rd., Hampton	2175	0		-5.6	Closed	
DCBE00	Street Light Projects		35.2			Active	M
DDCE00	Telephone Requests, Carryover		271.5		271.2	Active	H
DDCE01	3353 Line Relocation, State Rt. 101, Hampton	141047	0	2,150.00	271.2	Completed	
DEBE00	Highway Projects		163.1		234.2	Active	H
DEBE01	Replacement/Relocation of Poles, Lincoln Street, Exeter	181027	0		128.3	Closed	
DEBE02	Relocation and Changeover of Poles, Westville Rd., Plaistow	181039	0	73.2	0	Active	
DEBE03	Relocation of Poles, Epping Road, Exeter	181057	0	146	105.9	Completed	
Dec-00	Highway Projects, Carryover		0		22	Active	H
DECE01	Town of Exeter - Relocate Poles for Bridge Construction, Rt. 108,	171059	0		22	Closed	
DEOE01	Relocation of Highway Light	141079	0		0	Closed	H
DPBE01	Distribution Pole Replacements	181009	754.9	754.9	628.7	Active	M
DPBE02	Circuit 3H1 - Convert to 13.8 kV, Ocean Blvd., Hampton	181052	175.2	1,351.40	61.9	Active	I
DPBE03	Circuits 3H2 & 3H3 Convert to 13.8 kV, Hampton Beach	181056	25.3	450	73.9	Active	I
DPBE05	Circuits 5H1/5H2 - Transfer to 5X3, Witch Lane, Plaistow	181050	180.1	240.5	176.8	Active	I
DPBE99	Distribution Pole Replacements	191010	0		0	Active	M
DPCE01	Circuit 19X3- Convert Newfields Rd, Exeter Waste Water Treatment Plant	171023	43.3	358.4	27.5	Closed	I
DPCE02	Replace Primary Metering at Seabrook Nuke Plant	171060	74.1	213.7	223.1	Completed	M
DPNE01	Wind Storm - October 30, 2017	181034	0		123.1	Closed	M
DPNE03	Replace 3347A and 3347B Reclosers at 3347 Line Tap	181042	0	235	39.3	Active	M
DPNE04	Convert Portion of 43X1 to 6W2, Main St and Rt. 125, Kingston	181051	0	170	183.4	Active	I
DPNE06	Replace Structure 2055 on 3348 Sub T Line, Seabrook	181060	0	100	113.4	Completed	M
DPNE07	Replace Structure 2044 on 3348 Sub-Transmission Line, Hampton Falls	181061	0	78	0	Active	M
DPNE08	Wind/Snow Storm - March 7, 2018	181062	0		165.1	Closed	M
DPNE10	Wind Storm - March 2, 2018	181064	0		56.7	Closed	M
DPNE99	Anticipated Storm over $30K - Nonbudget		0			Active	M
DPOE01	Distribution Pole Replacement	171024	0	780	3.9	Closed	M
DPOE02	Reconductor Water Street, Exeter	171030	0		0	Closed	I
DPOE03	Relocate Main Line to Route 111, Kingston/Danville - Circuit 22X1	161014	0		-97	Closed	I
DPOE04	Distribution Upgrades to Accommodate Foss Manufacturing, Hampton	161037	0	630	0	Closed	I
DPOE05	Replace the 03341 and the 3352 Reclosers at Wolf Hill	13161	0		-19	Closed	M
DPOE06	Replace Overhead Pole Line with Underground Facilities for PEA	161053	0		0	Closed	I
DPOE07	Replace Failed Underground Cable, St. Magnus Condo's, Hampton	171050	0	113.7	0	Closed	M
DRBE00	Reliability Projects		461.7		454.5	Active	R
DRBE01	Installation of Recloser, Exeter Rd., Kingston - Circuit 43X1	181028	0	175	205.8	Completed	
DRBE07	3346 Line - Automatic Restoration Scheme	181030	0	570	119.8	Active	
DRBE16	Guinea Switching Reliability Enhancements	181046	0	188	128.9	Active	
DRCE00	Reliabilty Projects, Carryover		0			Active	R
DROE01	Install Devices with Pulsefinding	171020	0	413.5	32.7	Closed	R
	Sub-Totals:		2,909.80	9,939.40	3288.5		
BUDGET		AUTH	BUDGETED	AUTH	PROJECTED	PROJECT	

Electric Category	2018		Budget Category

CONSTRUCTION BUDGET 2018 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
NUMBER	DESCRIPTION	NUMBER	AMOUNT	AMOUNT	AMOUNT	STATUS	
	TOOLS, SHOP, GARAGE ELECTRIC						
EAEE01	Tools, Shop & Garage - Normal Additions and Replacements	181016	14	14	18.6	Active	O
EAEE02	Purchase and Replace Rubber Goods	181017	5.5	5.5	4.5	Active	O
EAEE03	Purchase and Replace Hot Line Tools	181018	4	4	4.8	Active	O
EAEE04	Normal additions & replacement - tools & equipment Meter	181010	7	7	3.9	Active	O
EAEE05	Normal Additions and Replacements- Tools and Equipment Substation	181023	8.5	8.5	8.8	Active	O
		Sub-Totals:	39	39	40.6		
BUDGET		AUTH	BUDGETED	AUTH	PROJECTED	PROJECT	
NUMBER	DESCRIPTION	NUMBER	AMOUNT	AMOUNT	AMOUNT	STATUS	
	TOOLS, SHOP, GARAGE GENERAL						
EAOE01	Tools, Shop & Garage - Normal Additions and Replacements	171016	0		2.2	Closed	O
EAOE02	Purchase and Replace Rubber Goods	171017	0		1.4	Closed	O
EAOE03	Purchase and Replace Hot Line Tools	171018	0		0	Closed	O
EAOE04	Normal Adds & Repl - Tools Meters & Services	171010	0		0	Closed	O
EAOE05	Normal Additions and Replacement - Tools and Equipment Substation	171021	0		5.4	Closed	O
EAOE06	Purchase/Replace Tools for Bucket Truck #28	171019	0		9.3	Closed	O
		Sub-Totals:	0	0	18.3		
BUDGET		AUTH	BUDGETED	AUTH	PROJECTED	PROJECT	
NUMBER	DESCRIPTION	NUMBER	AMOUNT	AMOUNT	AMOUNT	STATUS	
	LABORATORY GENERAL						
EBBE01	Lab Equipment - Normal Additions and Replacements	181011	7	7	6	Active	O
EBOE01	This covers unscheduled additions and replacements of lab instruments,	171011	0		0	Closed	O
		Sub-Totals:	7	7	6		
BUDGET		AUTH	BUDGETED	AUTH	PROJECTED	PROJECT	
NUMBER	DESCRIPTION	NUMBER	AMOUNT	AMOUNT	AMOUNT	STATUS	
	OFFICE ELECTRIC						
EDEE01	Office Furniture and Equipment	181015	3.5	3.5	2.1	Active	O
		Sub-Totals:	3.5	3.5	2.1		
BUDGET		AUTH	BUDGETED	AUTH	PROJECTED	PROJECT	
NUMBER	DESCRIPTION	NUMBER	AMOUNT	AMOUNT	AMOUNT	STATUS	
	OFFICE GENERAL						
EDOE01	Office Furniture and Equipment	171015	0		0.2	Closed	O
		Sub-Totals:	0	0	0.2		
BUDGET		AUTH	BUDGETED	AUTH	PROJECTED	PROJECT	
NUMBER	DESCRIPTION	NUMBER	AMOUNT	AMOUNT	AMOUNT	STATUS	
	STRUCTURES GENERAL						
GPBE01	Normal Improvements to Kensington Facility	181019	15	15	12.6	Active	O
GPCE01	Acquisition of New DOC & Sale of Existing DOC		1,000.00			Active	O
GPCE02	NewUES/Seacoast DOC Facility		1,000.00			Active	O
GPOE01	Electric system/life safety upgrades	13146	0		0	Closed	O
		Sub-Totals:	2,015.00	15	12.6		
BUDGET		AUTH	BUDGETED	AUTH	PROJECTED	PROJECT	
NUMBER	DESCRIPTION	NUMBER	AMOUNT	AMOUNT	AMOUNT	STATUS	
	SUBSTATION ELECTRIC						
SPBE01	Hampton Beach - 13kV Additions and other modifications	181047	314.2	1,199.00	169.4	Active	I
SPBE02	Replace Fence at Dow's Hill Substation	181024	65.6	66.6	0	Active	O
SPBE03	Install Stone in Dows Hill S/S &Guinea S/S	181026	26.7		18.4	Completed	O
SPBE99	Plaistow Substation #5 - Remove Foundations and Transformer	191013	0		0	Active	O
SPCE01	Guinea 18X1 - Replace Breaker and Relaying	161052	0		-0.4	Closed	O
SPNE01	Replace Failed bus PT at Guinea S/S	181053	0	72	56.9	Completed	M
SPOE01	Replace 19X3 Recloser	171012	0		-4.6	Closed	M
SPOE02	Replace Failed Insulators and Station Service Transformers	171048	0	91	1.1	Closed	M
		Sub-Totals:	406.5	1,428.60	240.8		
BUDGET		AUTH	BUDGETED	AUTH	PROJECTED	PROJECT	
NUMBER	DESCRIPTION	NUMBER	AMOUNT	AMOUNT	AMOUNT	STATUS	
	TRANSPORTATION ELECTRIC						
FEBE01	Replace Pickup Truck #7 - Fleet & Facilities		0			Active	
FEBE02	Replace Pickup Truck #36		0			Active	
FEBE03	Replave Pickup Truck #4- Metering Supervisor		0			Active	
FEBE04	Replace Pickup Truck #3/ meter worker		0			Active	
		Sub-Totals:	0	0			
		Grand Totals:	12,202.60	26,943.70	10,339.10		

Electric Category	2018		Budget Category

CONSTRUCTION BUDGET 2019 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	BLANKETS ELECTRIC						
BABC19	Electric T&D Improvements	190100	975.5	1,118.50	1,046.30	Active	M
BABC20	Electric T & D Improvements	200100	0		0	Active	M
BACC19	Electric T&D Improvements	180100	24.5	1,551.70	40.5	Completed 4/2019	M
BAOC17	2015 Electric T & D	150100	0		0	Closed 1/2019	M
BAOC18	Electric T&D Improvements	160100	0		0	Closed 5/2019	M
BAOC19	Electric T & D Improvements	170100	0	1,188.00	-0.1	Closed 1/2019	M
BBBC19	New Customer Additions	190101	270	417.5	431.6	Active	C
BBBC20	New Customer Additions	200101	0		0	Active	C
BBCC18	New Customer Additions	170101	0	420	0	Closed 1/2019	C
BBCC19	New Customer Additions	180101	26.3	448.9	29.9	Completed 4/2019	C
BCBC19	Outdoor Lighting	190102	84.1	136.1	145.4	Active	M
BCBC20	Outdoor Lighting	200102	0		0	Active	M
BCCC19	Outdoor Lighting	180102	3.6	127.4	5.6	Completed 3/2019	M
BDBC19	Emergency & Storm Restoration	190103	560.6	875.2	1,162.80	Active	M
BDBC20	Emergency & Storm Restoration	200103	0		0	Active	M
BDCC18	Emergency & Storm Restoration	170103	0	753	0	Closed 1/2019	M
BDCC19	Emergency & Storm Restoration	180103	9.1	821	-293.4	Completed 9/2019	M
BDOC19	Emergency & Storm Restoration	160103	0		0	Closed 1/2019	M
BEBC19	Billable Work	190104	168.7	173.3	145.5	Active	M
BEBC20	Billable Work	200104	0		0.8	Active	M
BECC19	Billable Work	180104	7.3	257.7	-19.8	Completed 4/2019	M
BEOC18	Billable Work	160104	0		0	Closed 5/2019	M
BEOC19	Billable Work	170104	0		0	Closed 1/2019	M
BFBC19	Transformer Purchases - Company	190105	497.1	421.2	392.2	Active	I
BFBC20	Transformer Purchases - Company	200105	0		0	Active	I
BFOC19	Transformer Purchases - Company Conversions	180105	0	51	0	Closed 12/2019	I
BGBC19	Transformer Purchases - Customer	190106	676.2	948.7	1,022.00	Active	C
BGBC20	Transformer Purchases - Customer	200106	0		0	Active	C
BGCC18	2017 Transformer Purchases - Customer	170106	0		0	Closed 1/2019	C
BGCC19	Transformer Purchases - Customer Requirements	180106	13.2	1,421.60	161.4	Closed 12/2019	C
BHBC19	Electric Meter Purchases - Company	190108	168.4	167.9	195.2	Active	M
BHBC20	Electric Meter Purchases - Company	200108	0		0	Active	M
BHOC19	Electric Meter Purchases - Company	180108	0	174.1	44.1	Closed 12/2019	M
BIBC19	Electric Meter Purchases - Customers	190107	434.3	433	451.6	Active	C
BIBC20	Electric Meter Purchases - Customer	200107	0		0	Active	C
BIOC18	2017 Meter Purchases - Customer	170107	0		0	Closed 5/2019	C
BIOC19	Electric Meter Purchases - Customers	180107	0	409.8	0	Closed 12/2019	C
Sub-Totals:			3,918.90	12,315.40	4,961.60		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS ELECTRIC						
ECEC01	Two Way Radio Replacements		3			Active	O
ECEC02	Radio Upgrade Project		363			Active	O
ECEC03	AMI Cell Modem Installations	190137	64.9	83.4	58.9	Active	O
ECEC04	Bridge St S/S AMI Contractor Inv - TS2 to PLX	190147	989.8	987.9	728.2	Active	O
Sub-Totals:			1,420.70	1,071.20	787.1		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS GENERAL						
ECNC01	UES – Software Licenses	200113	0		378.1	Closed 12/2019	O
ECNC02	General Software Enhancements - 2019	190126	0	18	15.7	Completed 11/2019	O
ECNC03	WebOps Replacement - Year 2 of 3	190127	0	16.8	20.3	Completed 11/2019	O
ECNC04	Reporting Blanket	190128	0	24	32.2	Completed 11/2019	O
ECNC05	Power Plan Updated License	190129	0		88.2	Closed 2/2019	O
ECNC06	Metersense Upgrade 4.2 to 4.3	190133	0	4.6	0.5	Closed 12/2019	O
ECNC07	2019 Infrastructure PC & Network	190141	0	501.8	310	Completed 12/2019	O
ECNC08	EE Tracking & Reporting System	190142	0	57.4	39.5	Active	O
ECNC10	Regulatory Work Blanket	190145	0	9.2	2.1	Completed 11/2019	O
ECNC11	2019 Interface Enhancements	190151	0	19.3	20.3	Completed 12/2019	O
ECNC12	2019 Customer Facing Enhancements	190152	0	295	361.7	Completed 12/2019	O
ECNC13	GIS Overlay in Electronic Inspection Platform	190157	0	19	20.7	Closed 4/2019	O
ECNC14	MV-90xi Upgrade v4.5 to 6.0	190178	0	38	0.9	Active	O
ECNC15	FCS Upgrade	190179	0	24.5	0.8	Completed 11/2019	O
ECNC17	OMS Upgrade to V9.1	190180	0	18.2	6.6	Closed 2/2019	O
ECNC18	GIS Enhancements	190185	0	6.8	6.4	Active	O
ECNC19	Replace MV-90 communication bank modules	190186	0	17.6	3.4	Completed 11/2019	O
ECNC20	Generator Interconnection Database	190189	0	54.4	50	Completed 12/2019	O
ECOC01	2018 IT Infrastructure	180120	0	173.5	12.4	Closed 6/2019	O
ECOC02	2018 Interface Enhancements	180132	0	216	-157	Cancelled 6/2019	O
ECOC03	2018 Customer Facing Enhancements	180133	0	280.5	-194.5	Closed 10/2019	O

Electric Category	2019
Growth	
Customer Additions (C)	2,525,300
Subtotal Growth	2,525,300
Non-Growth	
Reliability (R)	229,100
Maintenance Replacement (M)	5,733,000
Mandated (H)	0
System Improvement (I)	1,038,400
Grid Modernization (G)	0
Other (O)	3,046,800
Subtotal Non-Growth	10,047,300
Total	12,572,600
	12,572,600
	0

Budget Category	
Annual Requirements Blankets	**2019**
T&D Improvements	1,086,700
New Customer Additions	461,500
Outdoor Lighting	151,000
Emergency & Storm Restoration	869,400
Billable work	126,500
Transformers	1,575,600
Meters	690,900
Sub-Totals:	**4,961,600**
Distribution	
Overhead Line Extensions over $20,000	82,900
Underground Line Extensions over $20,000	345,900
Street Light Projects	-
Telephone Company Requests	-
Highway Projects	-
Distribution Pole Replacements	926,800
Specific Projects: Distribution	3,211,500
Sub-Totals:	**4,567,100**
Substation	
Specific Projects: Substation	1,077,000
Sub-Totals:	**1,077,000**
Communications	**1,725,700**
Tools, Shop, Garage	**122,200**
Laboratory	**6,900**
Office	**22,700**
Structures	**89,400**
Distribution Totals:	**12,572,600**

CONSTRUCTION BUDGET 2019 UES Capital

12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
ECOC04	Replace MV-90 communication bank modules	170128	0	6.7	0	Cancelled 1/2019	O
ECOC05	AMI Command Center Version Upgrade 6.5	170129	0		0	Cancelled 1/2019	O
ECOC06	GIS Version Upgrade & Data Model Consolidation	150129	0		0	Closed 4/2019	O
ECOC07	Upgrade Generator Interconnection Database	140141	0	56	-48.9	Active	O
ECOC08	2018 MeterSense Enhancements	180134	0	114	-48.2	Cancelled 6/2019	O
ECOC09	General Software Enhancements - 2018	180143	0	19.8	-1.9	Closed 4/2019	O
ECOC10	Electric Inspections Version Upgrade	170151	0		0	Cancelled 1/2019	O
ECOC11	2018 Cyber Security Enhancements	180146	0	45.6	-0.1	Closed 8/2019	O
ECOC12	OMS Regulatory Reports - Carry-over	180147	0	27.5	0	Closed 12/2019	O
ECOC13	IS Project Tracker Replacement	170172	0		0	Closed 4/2019	O
ECOC14	Microsoft Exchange Upgrade Carry-Over	180160	0	8.7	0	Closed 12/2019	O
ECOC15	Electronic Time Sheet-Phase Two	180162	0	28.1	3.5	Closed 12/2019	O
ECOC16	Universal Payment System (UPS) Reporting	180164	0		1.1	Closed 4/2019	O
ECOC17	Legacy Interface Job Rewrite	180141	0		1.3	Closed 4/2019	O
ECOC18	Dev / Staging Refresh	180140	0	13.9	9.5	Closed 12/2019	O
ECOC19	Move e-Intake estimating functionality into GEM	180139	0	30.6	0	Active	O
ECOC20	WebOps Replacement - Year 1 of 3	180142	0	21.2	-3.6	Closed 8/2019	O
ECOC21	TESS Replacement	180144	0		7.6	Closed 4/2019	O
ECOC22	Two Way Radio Replacements	180125	0	3	0	Closed 5/2019	O
ECOC23	Purchase Radio Recording System	180136	0	26	0	Closed 3/2019	O
Sub-Totals:			0	2,195.90	938.6		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	DISTRIBUTION ELECTRIC						
DABC00	Overhead Line Extensions		34.6		28.4	Active	C
DABC01	OH Line Ext along a public way Vaughn Rd. Bow	190155	0	8.3	8.9	Completed 9/2019	
DABC03	Three Phase Line Relocation 72 S Main St Concord-Billa	190164	0		4.5	Active	
DABC04	Single Phase, OH Line Extension 33 Bailey Rd Chicheste	190177	0	15.1	19.8	Completed 10/2019	
DABC05	Single Phase Overhead Line Ext-Relocate Pole, Anchor	190182	0		0.1	Closed 11/2019	
DABC06	Three Phase OH Line Ext-Relocate Pole & Anchor Per C	190183	0		0.3	Closed 11/2019	
DABC07	Three Phase OH Line Ext, 56 E Ricker Rd, Loudon-Non	190196	0	10.6	0	Active	
DABC08	Three Phase Overhead Line Ext 3 Merrimack St, Concor	190201	0	12.7	-5.2	Active	
DACC00	Overhead Line Extensions - Carryover		4.3		54.5	Completed 3/2019	C
DACC02	Three Phase, Temporary O/H Line Ext., 123 Pleasant St.	180126	0		13.4	Closed 12/2019	
DACC04	Single phase, OH line ext 228 Center Rd. Salisbury - Nor	180175	0	12	0.9	Completed 1/2019	
DACC05	Three phase OH Primary Silver Hills Dr Pembroke	180177	0		15.1	Closed 4/2019	
DACC06	Single Phase, O/H Line Extension. High St. Boscawen-B	180189	0		25.1	Closed 9/2019	
DBBC00	Underground Line Extensions		84		155.2	Active	C
DBBC01	Three Phase URD Line Ext-1 Minuteman Way, Concord-	190150	0	5.3	7.3	Completed 11/2019	
DBBC02	Underground Line Extension - S Main St., Concord	190156	0		18.1	Closed 10/2019	
DBBC03	Three phase URG Line Ext -406 Main St. Concord -Billab	190162	0		30.9	Closed 12/2019	
DBBC04	Three Phase URD Line Ext- Silver Hills Pembroke	190165	0		11.6	Closed 11/2019	
DBBC05	Single Phase, URD Line Extension. 226 Queen St, Bosca	190166	0	6.6	19.3	Closed 11/2019	
DBBC06	Three Phase, URD Line Ext. 13 Dunklee Rd. Bow-Billabl	190167	0	7.3	2.6	Active	
DBBC07	Single Phase URD Line Ext 10 Deer Track Ln, Concord	190170	0		3.2	Closed 11/2019	
DBBC08	Single Phase URD Line Extension 15 Morgan Dr, Bow	190187	0	1.5	-2.1	Active	
DBBC09	Three Phase URD Line Extension - 404 S Main St. Conc	190188	0	3.6	33.4	Completed 12/2019	
DBBC10	Three Phase UG Primary 89 Fort Eddy Rd, Concord-Billa	190193	0	17.3	49.6	Completed 11/2019	
DBBC11	Three phase URD Line Ext, 25 Sandquist St, Concord	190194	0	14	0	Active	
DBBC12	SINGLE PHASE URD LINE EXT 130 SNOW POND RD,	190195	0	4.8	4.1	Completed 12/2019	
DBBC13	Three Phase URD Primary Line Ext, 33 Canal St Penacc	190197	0	23.6	0	Active	
DBBC14	Single Phase Underground Line Ext. Sign Board I93 Sou	190199	0	3.1	-14.4	Active	
DBBC15	Single Phase OH/URD Line Ext 135 N State St, Concord	190200	0	22.4	-8.4	Active	
DBCC00	Underground Line Extensions, Carryover		10.3		190.7	Active	C
DBCC02	Tremont St Boscawen-California Fields-Primary urd line	160128	0		2.5	Closed 3/2019	
DBCC04	Single Phase, URD Line Ext., Tuscany Village, Riesling	180157	0		26.6	Closed 9/2019	
DBCC05	Vintage Estates, Sonoma Way Concord-singl ph urd line	170156	0		34.3	Closed 8/2019	
DBCC06	State of NH Liquor Commission 50 Storrs St-3 ph Line E	160143	0		0	Closed 1/2019	
DBCC07	Three Phase, URD Line Ext., 250 Pleasant St., Concord	180167	0	32.6	44.7	Active	
DBCC08	Three Phase, URD Line Ext., 285-287 Loudon Rd., Conc	180169	0	26.5	0	Closed 10/2019	
DBCC09	Single phase, URD LIne Extens. 33 Elkins Rd, Epsom	180176	0		-4.6	Completed 1/2019	
DBCC10	76 Mountain Rd Epsom Getaway House-OH & URD Prim	170173	0	25.9	0	Closed 1/2019	
DBCC11	Three Phase, URD Line Ext., 660 River Rd., Bow - Non E	180174	0	24.3	-0.5	Completed 1/2019	
DBCC12	Sunrise Meadows Senior Housing-Short Falls Rd Epsom	170153	0		-1.4	Closed 4/2019	
DBCC13	Single Phase URD Primary Line Ext. Fawn Court Bow No	180179	0	24.6	19.1	Closed 10/2019	
DBCC14	Single phase URD Line Ext. Oxbow Bluff -Penacook -Bill	180180	0		28.2	Closed 11/2019	
DBCC15	Three Phase URD Line Ext -77 Merrimack St. Penacook-	180182	0	21.5	1.6	Completed 1/2019	
DBCC16	Three Phase URD Line Ext 5-7 S State St. Concord-Non	180183	0		40.2	Closed 10/2019	
DCBC00	Street Light Projects		3.3			Active	M
DCCC00	Street Light Projects - Carryover		0.5			Completed 2/2019	M
DDBC00	Telephone Company Requests		13.8			Active	H

Electric Category	2019		Budget Category

CONSTRUCTION BUDGET 2019 UES Capital

12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DDCC00	Telephone Company Request - Carryover		1.4			Completed 2/2019	H
DEBC00	Highway Projects		64.9		0	Active	H
DECC00	Highway Projects, Carryover		6.5		0	Completed 2/2019	H
DPBC01	Condemned Poles Distribution	190112	568.2	874.5	926.8	Active	M
DPBC02	Build Circuit Tie 8X3-8X5 - Sheep Davis Rd. North, Concord	190144	88.5		103.4	Closed 11/2019	I
DPBC03	Replace Poles 93/1X and 93/2 and install 3 regulators	190171	52.9	52.8	70.4	Completed 12/2019	M
DPBC04	Re-conductor and re-insulate circuit 1H6	190149	805.9	250	159.1	Active	I
DPBC05	Porcelain Cutout Replacements	190130	185.2	185	183.5	Active	M
DPBC06	Perform Cable rejuvenating fluid injection on Phase C Cable	190153	179.3	178.8	162.8	Completed 9/2019	M
DPBC07	Install Conduit and Primary URD Cable between Pads 2 & 3	190159	54.5		59.6	Closed 12/2019	M
DPBC08	Install Conduit and Primary URD Cable between Pads 5 & 6	190160	38.2		62.2	Closed 12/2019	M
DPBC09	2H2 Spacer Cable Replacement		193.2			Cancelled 9/2019	M
DPBC10	Replace Recloser - Pole 27-1 - Water Street, Boscawen	190139	36.8	36.7	22.4	Active	M
DPBC11	Perform Cable rejuvenating fluid injection on Phase A Cable:	190154	89.5	89.2	102.3	Completed 9/2019	M
DPBC12	Replace Pad mounted switchgear Cir 1H2 and 1H3	190169	188.3	472.9	169.6	Active	M
DPBC13	Install three 100 Amp Regulators on P# 354/8	190161	99.1	80	34.9	Completed 10/2019	M
DPBC14	Install 3 Regulators on Pole # 33	190168	85.3	99.3	97.1	Completed 9/2019	M
DPCC01	Manhole improvements MH 17		201.8			Cancelled 3/2019	M
DPNC01	Install three phase Hendrix	190148	0	584.7	670	Completed 12/2019	M
DPNC02	Install Pullbox and Replace Failed Cable - Victorian Ln, Conc	190163	0		123.9	Closed 2/2019	M
DPNC03	Wind Event 7-10-18	180187	0		123.7	Closed 2/2019	M
DPNC05	Reconductor 1H6 - Pleasant and Green Street, Concord	190174	0	197.8	129.1	Active	I
DPNC06	Install Conduit and Cable from Riser P 209 to pad mount	190176	0		52.5	Closed 10/2019	M
DPNC07	Reconductor/Convert Circuit 1H6 - Thompson Street, Concor	190181	0	128.7	144.7	Active	I
DPNC08	Install Step-Down Transformers - Pole 33 - Hall St., Concord	190184	0	19.1	18.5	Active	I
DPNC09	Convert 10 sections of Basin Rd to 34.5 KV to serve new loa	190190	0	96.1	43.7	Active	M
DPNC12	Reconductor/Convert Circuit 1H6 - S Spring St., Concord	190192	0	138.9	94.3	Active	I
DPNC13	374 Line Rebuild with 15kV Underbuild	190198	0	1,066.00	0	Active	I
DPNC99	Primary Net Metering for the Hydro Dam	180184	0		0	Cancelled 1/2019	M
DPOC01	Condemned Poles quarter one 2017	170115	0		0	Closed 1/2019	M
DPOC02	Primary Net Metering for the Hydro Dam	180156	0	101.5	43.4	Closed 10/2019	M
DPOC03	Replace Man Hole roof with new precast roof	180181	0	277.4	185	Active	M
DPOC04	Rebuild Low Ave, Concord with Hendrix Construction	180172	0	134.8	126.3	Active	M
DPOC05	Replace Failed URD Primary Cable and add Pull Box	180188	0		0	Closed 10/2019	M
DPOC06	Replace Direct Burried cable with conduit and 35kv URD Cal	180171	0		0	Closed 9/2019	M
DRBC00	Reliability Projects		229.5		189.7	Active	R
DRBC04	Install Recloser & Fuse Saver - Bow Bog Road, Bow	190140	0	139.8	109.4	Closed 12/2019	
DRBC07	Install Animal protection on Distribution Transformers	190136	0	40	24.2	Active	
DRBC13	396X1 Tap - Install Recloser	190119	0	94.2	56	Active	
DRCC00	Reliabilty Projects, Carryover		0			Completed 3/2019	R
DROC10	Substation Reliability Enhancements at West Concord	180153	0		24.7	Closed 9/2019	R
DROC12	Install Recloser - Pole 60 - Bow Bog Rd., Bow	180163	0	108.8	14.7	Closed 12/2019	R
DROC15	Install 430 ft of conduit and 1/0 Al 35KV URD cable	170155	0		0	Closed 1/2019	R
Sub-Totals:			3,319.60	5,770.40	4567.1		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE ELECTRIC						
EAEC01	Purchase and Replace Rubber Goods	190132	5.5	5.5	9	Active	O
EAEC02	Purchase and Replace Hot Line Tools	190124	3.5	3.5	5	Active	O
EAEC03	Tools, Shop and Garage, Normal additions and replacement:	190113	14	14	2.8	Active	O
EAEC04	Normal additions & replacement - tools & equipment Meterin	190110	7	7	8.6	Active	O
EAEC05	Normal Additions and Replacements - Tools and Equipment	190121	8.5	8.5	11.2	Active	O
EAEC06	Purchase Omicron Relay Test Set	190146	70	70	67.1	Completed 12/2019	O
Sub-Totals:			108.5	108.5	103.7		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE GENERAL						
EAOC01	Tools, Shop & Garage - Normal Additions and Replacements	170116	0	13.5	0	Closed 1/2019	O
EAOC02	Purchase and Replace Rubber Goods	170117	0	5.5	0	Closed 1/2019	O
EAOC03	Purchase and Replace Hot Line Tools	170118	0	3.3	0	Closed 1/2019	O
EAOC04	Normal additions & replacement - tools & equipment Meterin	180111	0		9.1	Closed 4/2019	O
EAOC05	Normal Additions and Replacements - Tools and Equipment	180135	0		2.9	Closed 4/2019	O
EAOC06	Purchase tools for new Bucket Truck # 23	170167	0	5	0	Closed 1/2019	O
EAOC07	Purchase tools for new Digger truck # 30	180155	0		5.3	Closed 9/2019	O
EAOC08	Purchase and Replace Rubber Goods	180128	0	5.5	0	Closed 4/2019	O
EAOC09	Purchase and Replace Hot Line Tools	180129	0		0.4	Closed 4/2019	O
EAOC10	Tools, Shop & Garage - Normal Additions and Replacements	180127	0		0.8	Closed 1/2019	O
Sub-Totals:			0	32.8	18.5		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	LABORATORY GENERAL						

Electric Category	2019

Budget Category

CONSTRUCTION BUDGET 2019 UES Capital

12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
EBBC01	Lab Equipment - Normal Additions and Replacements	190111	7	7	6.9	Active	O
EBOC01	Lab Equipment - Normal Additions and Replacements	180112	0		0	Closed 4/2019	O
Sub-Totals:			7	7	6.9		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE ELECTRIC						
EDEC01	Office Furniture and Equipment Replacements	190122	3.5	3.5	6.7	Active	O
EDEC02	Furniture Replacements Year 1	190123	13	13	16	Active	O
Sub-Totals:			16.5	16.5	22.7		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE GENERAL						
EDOC01	Office Furniture and Equipment	180116	0		0	Closed 4/2019	O
Sub-Totals:			0	0	0		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	STRUCTURES GENERAL						
GPBC01	Normal Improvements to Capital Facility	190120	18	18	17	Active	O
GPNC01	Rooftop AC condenser replacement	190138	0	76.1	66.1	Active	O
GPOC01	Normal Improvements to Capital Facility	180119	0	15	6.1	Closed 5/2019	O
GPOC03	Physical Security Improvements	180121	0		0	Closed 9/2019	O
GPOC04	Office & Systems Furniture Reconfigurations	180122	0	129	0.2	Closed 4/2019	O
Sub-Totals:			18	238.1	89.4		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	SUBSTATION ELECTRIC						
SPBC01	Replace the 374J5 and the 374J6 Switches	190114	120.5	182.1	1.4	Active	O
SPBC02	Gulf Street - Outside Services	190118	926.6	2,925.00	734.7	Active	O
SPBC03	West Concord - Replace RTU and Upgrade Equipment	190115	216	280	0	Active	O
SPBC04	Install Crushed Stone at West Concord S/S	190135	51.6	51.4	42.4	Active	O
SPBC05	Bow Bog - Replace SCADA RTU	190116	61.9	61.7	18.9	Active	O
SPBC06	Hazen Drive - Replace SCADA RTU	190117	50.4	50.2	34.6	Active	O
SPCC01	Bridge Street - Replace 35KV Line Relaying & Modify RTU	180149	279.6	672.2	244.7	Completed 10/2019	O
SPOC01	Install 2nd AMI TCU at Penacook	180138	0	80.2	3.2	Closed 2/2019	O
SPOC02	Landgon S/S - Replace 374J5 & 375J6	170125	0	64.4	0	Cancelled 1/2019	O
SPOC03	Broken Ground - Site Evaluation, Permitting, Preliminary Sur	140144	0	12,620.00	-2.9	Closed 2/2019	I
Sub-Totals:			1,706.50	16,987.30	1,077.00		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TRANSPORTATION ELECTRIC						
FEBC01	Replace Wire Reel Trailer T-17		0			Active	
Sub-Totals:			0	0			
Grand Totals:			10,515.70	38,743.20	12,572.60		

Electric Category	2019

Budget Category

CONSTRUCTION BUDGET 2019 UES Seacoast

12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	BLANKETS ELECTRIC						
BABE19	Electric T & D Improvements	191000	1,441.90	1,441.50	1,384.50	Active	M
BABE20	Electric & T&D Improvements	201000	0		1.2	Active	M
BACE19	Electric T&D Improvements	181000	26.4	1,806.60	-6.4	Completed 4/2019	M
BAOE17	2015 Electric T&D	151000	0		0	Closed 1/2019	M
BAOE18	Electric T&D Improvements	161000	0	1,556.70	0	Closed 1/2019	M
BAOE19	Electric T & D Improvements	171000	0	1,955.00	0	Closed 2/2019	M
BBBE19	New Customer Additions	191001	387.9	386.2	421.9	Active	C
BBBE20	New Customer Additions	201001	0		0	Active	C
BBCE19	NewCustomer Additions	181001	15.4	575.2	4.7	Completed 4/2019	C
BBOE18	New Customer Additons	161001	0		0	Closed 1/2019	C
BBOE19	New Customer Additions	171001	0	559.4	0	Closed 2/2019	C
BCBE19	Outdoor Lighting	191002	197.4	196.4	143.9	Active	M
BCBE20	Outdoor Lighting	201002	0		0	Active	M
BCCE19	Outdoor Lighting	181002	6.2	240.6	14.7	Completed 4/2019	M
BCOE19	Outdoor Lighting	171002	0	276.8	0	Closed 2/2019	M
BDBE19	Emergency & Storm Restoration	191003	391.2	438.8	1,597.00	Active	M
BDBE20	Emergency & Storm Restoration	201003	0		1	Active	M
BDCE19	Emergency & Storm Restoration	181003	13.7	704.5	-151.8	Active	M
BDOE18	Emergency & Storm Restoration	161003	0		0	Closed 1/2019	M
BDOE19	Emergency & Storm Restoration	171003	0	575.2	0	Closed 2/2019	M
BEBE19	Billable Work	191004	289.5	325.3	295.2	Active	M
BEBE20	Billable Work	201004	0		0	Active	M
BECE19	Billable Work	181004	0	410.6	-37.8	Active	M
BEOE17	2015 Billable Work	151004	0	390.1	0	Closed 1/2019	M
BEOE18	Billable Work	161004	0		0	Closed 1/2019	M
BEOE19	Billable Work	171004	0	410.1	0	Closed 2/2019	M
BFBE19	Transformer Purchases - Company	191005	215.8	215.1	127.3	Active	I
BFBE20	Transformer Purchases - Company	201005	0		0	Active	I
BFOE19	Transformer Purchases - Company	181005	0	859.8	0	Closed 12/2019	I
BGBE19	Transformer Purchases - Customer	191006	1,010.50	1,010.60	1,039.90	Active	C
BGBE20	Transformer Purchases - Customer	201006	0		0	Active	C
BGCE18	2017 Transformer Purchases - Customer	171006	0	1,154.10	0	Closed 1/2019	C
BGCE19	Transformer Purchases - Customer O/H	181006	61.6	1,320.70	195.9	Closed 12/2019	C
BHBE19	Electric Meter - Company	191008	282	281.2	239.7	Active	M
BHBE20	Electric Meter Purchases - Company	201008	0		0	Active	M
BHOE19	Electric Meter - Company	181008	0	305.1	0.9	Closed 12/2019	M
BIBE19	Electric Meter - Customer	191007	532.3	530.8	530.8	Active	C
BIBE20	Electric Meter Purchases - Customer	201007	0		0	Active	C
BIOE18	2017 Meter Purchases - Customer	171007	0		0	Closed 1/2019	C
BIOE19	Electric Meter - Customer	181007	0	447.3	0	Closed 1/2019	C
Sub-Totals:			4,871.80	18,373.70	5,802.60		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS ELECTRIC						
ECEE01	Two Way Radio Replacements		5			Active	O
ECEE02	AMI Cell Modem Installations	191039	97	96.8	78.1	Active	O
Sub-Totals:			102	96.8	78.1		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS GENERAL						
ECOE01	Radio Replacement Project	181022	0	222	0.1	Closed 10/2019	O
Sub-Totals:			0	222	0.1		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	DISTRIBUTION ELECTRIC						
DABE00	Overhead Line Extensions - New Projects		25		63	Active	C
DABE01	Single Phase, O/H Line Ext., 41 Kimball F	191044	0	5.7	10.3	Closed 1/2019	
DABE02	Single Phase, O/H Line Ext., 10 Dodge R	191049	0		3.9	Closed 11/2019	
DABE03	Single Phase, O/H Line Ext., 18 Moulton I	191053	0		0.1	Closed 11/2019	
DABE04	Three Phase, O/H Line Ext., 157 Plaistow	191057	0		3.1	Closed 12/2019	
DABE05	Single Phase, O/H Line Ext., Marshall Rd	191059	0	26.5	19.3	Completed 11/2019	
DABE06	Three Phase, Overhead Line Ext., 139 La	191064	0	4	8.2	Closed 12/2019	
DABE07	Three Phase, Overhead Line Ext., 81 Led	191067	0	15.7	18.1	Completed 11/2019	
DACE00	Overhead Line Extensions, Carryover		9.5		27.3	Active	C
DACE01	Relocation of Pole, Three Phase Service,	181012	0		-5.4	Closed 12/2019	

Electric Category	2015
Growth	
Customer Additions (C)	2,925,100
Subtotal Growth	2,925,100
Non-Growth	
Reliability (R)	691,400
Maintenance Replacement (M)	5,416,200
Mandated (H)	23,500
System Improvement (I)	3,471,500
Grid Modernization (G)	0
Other (O)	3,968,500
Subtotal Non-Growth	13,571,100
Total	16,496,200

16,496,200
0

Budget Category	
Annual Requirements Blankets	**2019**
T&D Improvements	1,379,300
New Customer Additions	426,600
Outdoor Lighting	158,600
Emergency & Storm Restoration	1,446,200
Billable work	257,400
Transformers	1,363,100
Meters	771,400
Sub-Totals:	**5,802,600**
Distribution	
Overhead Line Extensions over $20,000	90,300
Underground Line Extensions over $20,000	641,600
Street Light Projects	-
Telephone Company Requests	-
Highway Projects	23,500
Distribution Pole Replacements	1,358,700
Specific Projects: Distribution	3,100,300
Sub-Totals:	**5,214,400**
Substation	
Specific Projects: Substation	1,771,300
Sub-Totals:	**1,771,300**
Communications	**78,200**
Tools, Shop, Garage	**66,500**
Laboratory	**54,600**
Office	**2,800**
Structures	**3,505,800**
Distribution Totals:	**16,496,200**

CONSTRUCTION BUDGET 2019 UES Seacoast

12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DACE02	Single Phase, Overhead Line Ext., 26 Mo	181049	0	5.4	0	Completed 1/2019	
DACE03	Single Phase, O/H Line Ext., Bent Grass	181065	0		1	Closed 1/2019	
DACE04	Single Phase, Overhead Line Ext., 53 Hig	171063	0	6	0	Closed 1/2019	
DACE05	Three Phase, O/H Line Ext., Off Rocks R	181070	0		23.8	Closed 9/2019	
DACE06	Three Phase, O/H Line Ext., 137 Folly Mil	181067	0		7.9	Closed 3/2019	
DBBE00	Underground Line Extensions - New Projects		207.1		293.5	Active	C
DBBE01	Single Phase, URD Line Ext., Ward Way	191072	0	37.8	-11.9	Closed 11/2019	
DBBE02	Single Phase, URD Line Ext., 98 Linden S	191041	0		38.9	Closed 11/2019	
DBBE03	Install Underground Secondary, 482 High	191045	0		3.1	Closed 11/2019	
DBBE04	Three Phase, URD Line Ext., 700 Lafayet	191046	0	12	7.5	Completed 12/2019	
DBBE05	Single Phase, URD Line Ext., Old County	191047	0	44.2	42.2	Completed 11/2019	
DBBE07	Single Phase, URD Line Ext, 236 Winnac	191050	0	26.4	33.9	Completed 12/2019	
DBBE09	Single Phase, URD Line Ext., 663 Exeter	191052	0		38.5	Closed 12/2019	
DBBE10	Three Phase, URD Line Ext., 27 Brown R	191051	0		7.9	Closed 12/2019	
DBBE11	Three Phase, URD Line Ext., 106 Ledge I	191054	0		19.2	Closed 11/2019	
DBBE12	Three Phase, URD Line Ext., 315 Ocean	191056	0	9.3	-3.7	Active	
DBBE13	Single Phase, URD Line Ext., Heritage La	191061	0	40	8.9	Active	
DBBE14	Single Phase, URD Line Ext., 69 Main St.	191062	0	10.3	-6.1	Active	
DBBE15	Three Phase, URD Line Ext., 127 Plaistow	191063	0	25.1	64.8	Completed 12/2019	
DBBE16	Three Phase, URD Line Ext., 9 Puzzle Ln	191066	0	14.4	28.1	Completed 11/2019	
DBBE17	Single Phase, URD Line Ext., 177 North I	191069	0	11.6	0.8	Completed 11/2019	
DBBE18	Three Phase, URD Line Ext., 60 Portsmo	191070	0	13	-1.6	Active	
DBBE20	Three Phase, URD Line Ext., 82 Newton	191055	0	19	23.1	Completed 11/2019	
DBCE00	Underground Line Extensions, Carryovers		198.1		328.1	Active	C
DBCE01	Three Phase, URD Line Ext., 118 Portsm	181048	0		-2.2	Closed 2/2019	
DBCE03	Single Phase, URD Line Ext., Rollins Far	171027	0		0	Closed 1/2019	
DBCE04	Three Phase, URD Line Ext., Country Clu	181031	0	119.5	-54.5	Closed 12/2019	
DBCE05	Single Phase, URD Line Ext., Willowbroo	181032	0		-2.1	Closed 2/2019	
DBCE06	Three Phase, URD Line Ext., Exeter Rd.,	171035	0		22.3	Closed 11/2019	
DBCE07	Three Phase, URD Line Ext., 183 Epping	181059	0		103.1	Closed 11/2019	
DBCE08	Single Phase, URD Line Ext., 8 Kingston	181069	0		16.5	Closed 10/2019	
DBCE09	Three Phase, URD Line Ext, Main St., Kir	181041	0		52.1	Closed 4/2019	
DBCE10	Single Phase, URD Line Ext., 460 East R	181044	0		2.4	Closed 2/2019	
DBCE11	Single Phase, URD Line Ext., 199 South	181071	0		25.1	Closed 3/2019	
DBCE12	Single Phase, URD Line Ext., Whittaker V	181068	0		20.4	Closed 10/2019	
DBCE14	Single Phase, URD Line Ext., McCarron I	181038	0		0.9	Closed 2/2019	
DBCE15	Single Phase and Three Phase, URD Lin	181029	0	174.1	91.2	Closed 12/2019	
DBCE16	Three Phase, URD Line Ext., Mill Rd., Ha	181040	0	6.2	52.9	Active	
DBCE17	Three Phase, URD Line Ext., 3 Meeting F	181033	0		0	Closed 1/2019	
DBOE01	Single Phase, URD Line Ext., 199 South Rd.,	171026	0	11.1	0	Closed 1/2019	C
DBOE02	Three Phase, URD Line Ext., 277 Water St, E	171054	0		21.4	Closed 11/2019	C
DBOE03	Single Phase, URD Line Ext., Rollins Farm R	171058	0		-1.4	Closed 2/2019	C
DCBE00	Street Light Projects		23.7			Active	M
DCCE00	Street Light Projects, Carryover		0			Active	M
DDBE00	Telephone Company Requests		0			Active	H
DDCE00	Telephone Company Requests, Carryover		0			Active	H
DEBE00	Highway Projects		176.7		23	Active	H
DEBE01	Relocation and Changeover of Poles, We	191034	0		23	Closed 11/2019	
Dec-00	Highway Projects, Carryover		20.8		0.5	Active	H
DECE01	Relocation of Poles, Epping Road, Exeter	181057	0		0.5	Closed 2/2019	
DECE02	Relocation and Changeover of Poles, We	181039	0		0	Cancelled 1/2019	
DPBE01	Distribution Pole Replacements	201009	989.2		1,123.10	Active	M
DPBE02	Porcelain Cutout Replacements, Various Loc	191022	185.2	184.7	104.1	Active	M
DPBE03	Circuit 6W1 - Install Regulator, Burnt Swamp	191024	39.5		27.3	Closed 12/2019	M
DPBE04	Install Voltage Regulator	201010	417.3		207.3	Active	M
DPBE05	Install Voltage Regulator	201011	46.1		0	Cancelled 4/2019	M
DPCE01	Distribution Pole Replacements	191010	58.9	986.2	102.8	Closed 4/2019	M
DPCE02	Circuit 3H1 - Convert to 13.8 kV, Ocean Blvd	181052	937.9	1,351.40	1,087.60	Active	I
DPCE03	Circuits 3H2 & 3H3 Convert to 13.8 kV, Ham	181056	468.2		395.7	Closed 10/2019	I
DPCE04	Convert Portion of 43X1 to 6W2, Main St and	181051	22.1		10.7	Closed 4/2019	I
DPCE05	Replace 3347A and 3347B Reclosers at 334	181042	164.6	235	118.7	Completed 11/2019	M
DPCE06	Circuits 5H1/5H2 - Transfer to 5X3, Witch La	181050	39.2		48.8	Closed 4/2019	I
DPNE01	Replace Structure 2011 on 3348 Sub-Transm	191014	0		54.6	Closed 10/2019	M
DPNE02	Distribution work for PV facility at 199 South	191042	0		-12	Completed 9/2019	M
DPNE03	Convert and Transfer Portion of 5X3 to 13W1	191065	0	155	14.8	Active	I
DPNE04	Circuit 6W1 - Convert Chase Road, South Ha	191068	0	275	64.8	Active	I

Electric Category	2015

Budget Category

CONSTRUCTION BUDGET 2019 UES Seacoast

12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DPOE01	Distribution Pole Replacement	171024	0		0	Closed 1/2019	M
DPOE02	Replace Primary Metering at Seabrook Nuke	171060	0	287.8	0	Closed 7/2019	M
DPOE03	Relocate Main Line to Route 111, Kingston/D	161014	0		0	Closed 1/2019	M
DPOE04	Establish 5X3/58X1 Distribution Circuit Tie, M	191025	0	416.1	211.1	Closed 1/2019	I
DPOE05	Replace the 03341 and the 3352 Reclosers a	13161	0		0	Closed 1/2019	M
DPOE06	Kingston S/S AMI Equip - TS2 to PLX	181058	0	199.6	130	Active	M
DPOE07	Replace Failed Underground Cable, St. Mag	171050	0		0	Closed 1/2019	M
DPOE09	Replace Structure 2055 on 3348 Sub T Line,	181060	0		0	Closed 4/2019	M
DPOE10	Replace Structure 2044 on 3348 Sub-Transm	181061	0		78.2	Closed 2/2019	M
DRBE00	Reliability Projects		799.8		235.5	Active	R
DRBE07	Install Hydraulic Reclosers, North Shore I	191032	0		28.9	Closed 9/2019	
DRBE08	Install Electronic Recloser, Little River Rc	191033	0	85	100.7	Completed 11/2019	
DRBE09	Circuit 13W2, Install Reclosers, Various L	191058	0	250	56	Active	
DRBE14	Circuit 19X2 - Distribution Automation Sc	191040	0	205.3	49.8	Active	
DRCE00	Reliabilty Projects, Carryover		0		440.3	Active	R
DRCE01	3346 Line - Automatic Restoration Schem	181030	378.3	570	440.3	Completed 8/2019	
DROE01	Install Devices with Pulsefinding	171020	0		0	Closed 1/2019	R
DROE02	Installation of Recloser, Exeter Rd., Kingston	181028	0		9.6	Closed 10/2019	R
DROE16	Guinea Switching Reliability Enhancements	181046	0	188	6	Closed 10/2019	R
Sub-Totals:			5,207.30	6,026.40	5,214.40		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE ELECTRIC						
EAEE01	Tools, Shop & Garage - Normal Additions an	191015	14.5	14.5	18.9	Active	O
EAEE02	Purchase and Replace Rubber Goods	191016	6	6	3	Active	O
EAEE03	Purchase and Replace Hot Line Tools	191017	4.5	4.5	7.4	Active	O
EAEE04	Normal additions & replacement - tools & equ	191030	7	7	7.7	Active	O
EAEE05	Normal Additions and Replacements- Tools a	191026	8.5	8.5	10.6	Active	O
EAEE06	Purchase and Replace Tools for New Truck #	191018	7	7	7.4	Active	O
EAEE07	Purchase Tools for New Back Yard Lift	191019	3	3	1.3	Active	O
Sub-Totals:			50.5	50.5	56.3		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE GENERAL						
EAOE01	Tools, Shop & Garage - Normal Additions an	181016	0		0	Closed 4/2019	O
EAOE02	Purchase and Replace Rubber Goods	181017	0		2.3	Closed 4/2019	O
EAOE03	Purchase and Replace Hot Line Tools	181018	0		3.9	Closed 4/2019	O
EAOE05	Normal Additions and Replacements- Tools a	181023	0	8.5	0	Closed 4/2019	O
EAOE10	Normal additions & replacement - tools & equ	181010	0	7	4	Closed 4/2019	O
Sub-Totals:			0	15.5	10.2		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	LABORATORY GENERAL						
EBBE01	Lab Equipment - Normal Additions and Repla	191011	7	7	9.3	Active	O
EBBE02	Purchase Meter Shop Test Station	191012	53.5	53.5	45.3	Completed 10/2019	O
EBOE01	Lab Equipment - Normal Additions and Repla	181011	0		0	Closed 4/2019	O
Sub-Totals:			60.5	60.5	54.6		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE GENERAL						
EDBE01	Office Furniture and Equipment Replacemen	191028	3.5	3.5	2.8	Active	O
EDOE01	Office Furniture and Equipment	181015	0		0	Closed 4/2019	O
Sub-Totals:			3.5	3.5	2.8		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	STRUCTURES GENERAL						
GPBE01	Normal Improvements to Seacoast DOC Fac	191027	18	18	14.8	Active	O
GPBE02	Legal . Insurance, Permitting & Misc	191060	5,000.00	15,931.50	2,089.40	Active	O
GPBE03	Acquisition of New DOC & Sale of Existing D	191035	1,200.00	1,200.00	1,373.70	Active	O
GPCE01	Acquisition of New DOC & Sale of Existing D	181054	0		0	Cancelled 1/2019	O
GPNE01	Plaistow Garage - Roof improvements	191043	0	28	27.9	Active	O
GPOE01	Normal Improvements to Kensington Facility	181019	0		0	Closed 3/2019	O
Sub-Totals:			6,218.00	17,177.50	3,505.80		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	SUBSTATION ELECTRIC						

Electric Category	2015

Budget Category

CONSTRUCTION BUDGET 2019 UES Seacoast

12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
SPBE01	Plaistow Substation #5 - Remove Foundatior	191013	98.5	131.4	122.5	Completed 11/2019	O
SPBE02	Install Crushed Stone at Mill Lane Tap	191037	43.9	43.8	-22.2	Active	O
SPBE03	Replace Fence at Timberlane S/S	191038	83.6	99.6	103.2	Active	O
SPBE04	Replace Substation Locks	191021	25	25	27.5	Completed 9/2019	O
SPBE05	Stard Road - Replace SCADA RTU	191023	50.4	50.2	15.1	Completed 5/2019	O
SPBE06	Kingston - Modifications & Additions	191071	56.3	56.3	0	Active	I
SPCE01	Hampton Beach - 13kV Additions and other n	181047	1,630.20	1,552.00	1,510.70	Completed 7/2019	I
SPOE01	Replace Failed bus PT at Guinea S/S	181053	0		1.8	Closed 1/2019	O
SPOE02	Replace Failed Insulators and Station Servic	171048	0	91	0	Closed 1/2019	O
SPOE03	Replace Fence at Dow's Hill Substation	181024	0	66.6	12.7	Closed 10/2019	O
Sub-Totals:			1,987.90	2,115.80	1,771.30		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TRANSPORTATION ELECTRIC						
FEBE01	Purchase Off Road/Back Yard Lift		0			Active	
FEBE02	Replace Bucket Truck #21		0			Active	
FEBE03	Replace Pickup Truck #35 - Line Supervisor		0			Active	
FEBE04	Replace Pickup Truck #22 - Substation		0			Active	
FEBE05	Replace trailer T-4 (Flatbed)		0			Active	
FEBE06	Replace Wire Reel Trailer T-3		0			Active	
FEBE07	Replace Fork Lift-Heavy (Propane)		0			Active	
FEBE08	NewFork Lift - Light (Electric)		0			Active	
Sub-Totals:			0	0			
Grand Totals:			18,501.60	44,142.10	16,496.20		

Electric Category	2015

Budget Category

CONSTRUCTION BUDGET 2020 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	?? ??						
XXXC01	Pension & PBOP Allocation 2018 & 2019	200162	0		0	Closed 6/2020	O
BB0C18	New Customer Additions	170101	0		0	Closed 1/2020	O
		Sub-Totals:	0	0	0		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	BLANKETS ELECTRIC						
BABC20	Electric T & D Improvements	200100	1,089.00	1,107.50	1,383.20	Active	M
BABC21	Electric T& D Improvements	210100	0		0	Active	M
BACC20	Electric T&D Improvements	190100	24.8	1,118.50	37.3	Active	M
BAOC18	Electric T & D Improvements	170100	0	1,188.00	0.1	Closed 1/2020	M
BAOC19	Electric T&D Improvements	180100	0	1,551.70	7.8	Closed 1/2020	M
BBBC20	New Customer Additions	200101	380.1	493.4	537.2	Active	C
BBBC21	New Customer Additions	210101	0		0.6	Active	C
BBCC16	2015 New Customer Additions	150101	0	475	0	Completed 1/2020	C
BBCC18	New Customer Additions	170101	0		0	Closed 1/2020	C
BBCC19	New Customer Additions	180101	0		0	Closed 1/2020	C
BBCC20	New Customer Additions	190101	29.4	417.5	44.5	Completed 2/2020	C
BBOC18	New Customer Additions	170101	0	420	0	Closed 1/2020	C
BBOC18	New Customer Additions	170101	0		0	Closed 1/2020	C
BBOC19	New Customer Additions	180101	0	448.9	0	Closed 1/2020	C
BCBC20	Outdoor Lighting	200102	96.2	146	134.2	Active	M
BCBC21	Outdoor Lighting	210102	0		0	Active	M
BCCC18	Outdoor Lighting	170102	0		0	Closed 1/2020	M
BCCC20	Outdoor Lighting	190102	4	136.1	-0.8	Completed 4/2020	M
BCOC19	Outdoor Lighting	180102	0	127.4	0	Closed 1/2020	M
BDBC20	Emergency & Storm Restoration	200103	615.4	625	689.6	Active	M
BDBC21	Emergency & Storm Restoration	210103	0		0	Active	M
BDCC18	Emergency & Storm Restoration	170103	0	753	0	Closed 1/2020	M
BDCC19	Emergency & Storm Restoration	180103	0	821	-7	Closed 1/2020	M
BDCC20	Emergency & Storm Restoration	190103	10.1	875.2	-366.7	Active	M
BDOC19	Emergency & Storm Restoration	160103	0		0.1	Closed 1/2020	M
BEBC20	Billable Work	200104	188.9	220	243.2	Active	M
BEBC21	Billable Work	210104	0		0	Active	M
BECC20	Billable Work	190104	8	173.3	36.5	Completed 5/2020	M
BEOC18	Billable Work	160104	0	285	-0.1	Completed 1/2020	M
BEOC19	Billable Work	180104	0	257.7	-12.1	Closed 1/2020	M
BFBC20	Transformer Purchases - Company	200105	84.1	406.1	412.4	Active	I
BFBC21	Transformer Purchases - Companay Conver	210105	0		0	Active	I
BFCC20	Transformer Purchases - Company	190105	10.9	421.2	64.9	Completed 1/2020	I
BFOC19	Transformer Purchases - Company Conversi	180105	0	51	0	Closed 1/2020	I
BGBC20	Transformer Purchases - Customer	200106	741.4	333.6	1,153.50	Active	C
BGBC21	Transformer Purchases - Customer Requirer	210106	0		0	Active	C
BGCC19	Transformer Purchases - Customer Requirer	180106	0	1,421.60	0	Closed 1/2020	C
BGCC20	Transformer Purchases - Customer	190106	83.7	948.7	18.5	Completed 6/2020	C
BHBC20	Electric Meter Purchases - Company	200108	174.9	174.9	183.2	Active	M
BHBC21	Electric Meter Purchases - Company Require	210108	0		0	Active	M
BHOC19	Electric Meter Purchases - Company	180108	0		-5.5	Closed 1/2020	M
BHOC20	Electric Meter Purchases - Company	190108	0	167.9	-4.5	Completed 3/2020	M
BIBC20	Electric Meter Purchases - Customer	200107	466.6	466.6	508.3	Active	C
BIBC21	Electric Meter Purchases - Customer Requir	210107	0		0	Active	C
BIOC20	Electric Meter Purchases - Customers	190107	0	433	13.8	Completed 1/2020	C
		Sub-Totals:	4,007.20	16,464.60	5,072.20		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS ELECTRIC						
ECEC01	Two Way Radio Replacements		4			Active	O
EECC01	Radio Upgrade Project	200195	250	105	0	Active	O
EECC02	Upgrade TS2 to PLX Infrastructure Carryover		173.9			Active	O
		Sub-Totals:	427.9	105	0		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS GENERAL						
ECNC01	UES – Software Licenses	200113	0		331.3	Active	O
ECNC02	2020 IT Infrastructure Budget	200134	0		492.5	Completed 12/2020	O
ECNC03	2020 Customer Facing Enhancements	200135	0	279.7	232	Completed 12/2020	O

Electric Category	2019
Growth	
Customer Additions (C)	2,550,700
Subtotal Growth	2,550,700
Non-Growth	
Reliability (R)	417,700
Maintenance Replacement (M)	4,747,000
Mandated (H)	138,200
System Improvement (I)	4,259,400
Grid Modernization (G)	0
Other (O)	1,944,900
Subtotal Non-Growth	11,507,200
Total	14,057,900

14,057,900
0

Budget Category	
Annual Requirements Blankets	**2020**
T&D Improvements	1,428,400
New Customer Additions	582,300
Outdoor Lighting	133,400
Emergency & Storm Restoration	316,000
Billable work	267,500
Transformers	1,649,300
Meters	695,300
Sub-Totals:	**5,072,200**
Distribution	
Overhead Line Extensions over $20,000	66,400
Underground Line Extensions over $20,000	207,900
Street Light Projects	-
Telephone Company Requests	-
Highway Projects	138,200
Distribution Pole Replacements	1,538,600
Specific Projects: Distribution	2,350,900
Sub-Totals:	**4,302,000**
Substation	
Specific Projects: Substation	2,826,000
Sub-Totals:	**2,826,000**
Communications	**1,762,600**
Tools, Shop, Garage	**54,100**
Laboratory	**3,800**
Office	**1,000**
Structures	**36,200**
Distribution Totals:	**14,057,900**

Electric Category	2019

Budget Category

CONSTRUCTION BUDGET 2020 UES Capital

12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
ECNC04	Metersense Upgrade 2020	200136	0	5.1	0.6	Completed 12/2020	O
ECNC05	2020 Interface Enhancements	200137	0	69.2	50.2	Completed 12/2020	O
ECNC06	Regulatory Work Blanket	200138	0	15.1	12.8	Active	O
ECNC08	2020 General Software Enhancements	200140	0	15.5	1.5	Completed 12/2020	O
ECNC09	Reporting Blanket	200141	0	38.8	37.8	Completed 12/2020	O
ECNC11	Universal Payment System Enhancements	200143	0	24	1.2	Active	O
ECNC12	DevOps Implementation Project	200144	0	72.1	54.7	Active	O
ECNC13	AMI Command Center Upgrade X.X - 2020	200145	0	60	37.3	Closed 12/2020	O
ECNC14	Cyber Security Enhancements	200146	0	35.2	36.9	Completed 11/2020	O
ECNC15	Cloud Data Warehouse	200147	0	15.5	1.9	Active	O
ECNC16	Power Plan Upgrade	200167	0	142.5	111.9	Completed 12/2020	O
ECNC17	Damage Assessment Mobile Platform - Grid	200185	0	442	9.7	Active	O
ECNC18	Debt Management Software	200189	0	14	0	Active	O
ECNC19	Customer Experience Mgmt Project Year 1 o	200191	0	160	46.3	Active	O
ECNC99	2020 Infrastructure PC & Network	210113	0		0	Active	O
ECOC01	AMI Cell Modem Installations	190137	0	83.4	2.4	Closed 2/2020	O
ECOC02	Bridge St S/S AMI Contractor Inv - TS2 to PL	190147	0	987.9	193.9	Active	O
ECOC03	2019 Voice System Replacement	190125	0		-3.7	Closed 8/2020	O
ECOC04	General Software Enhancements - 2019	190126	0		3.2	Closed 8/2020	O
ECOC05	WebOps Replacement - Year 2 of 3	190127	0		1.4	Closed 8/2020	O
ECOC06	Reporting Blanket	190128	0		3.1	Closed 8/2020	O
ECOC07	Upgrade Generator Interconnection Databas	140141	0	56	0	Cancelled 1/2020	O
ECOC08	2019 Infrastructure PC & Network	190141	0		4.2	Closed 8/2020	O
ECOC09	EE Tracking & Reporting System	190142	0	64.6	41.7	Closed 12/2020	O
ECOC10	Regulatory Work Blanket	190145	0		6.9	Closed 8/2020	O
ECOC11	2019 Interface Enhancements	190151	0		0.8	Closed 8/2020	O
ECOC12	2019 Customer Facing Enhancements	190152	0		10.3	Closed 8/2020	O
ECOC13	GIS Overlay in Electronic Inspection Platform	190157	0		0	Closed 8/2020	O
ECOC14	MV-90xi Upgrade v4.5 to 6.0	190178	0	38	14.4	Closed 12/2020	O
ECOC15	FCS Upgrade	190179	0	24.5	10.5	Completed 1/2020	O
ECOC16	OMS Upgrade to V9.1	190180	0		4.5	Closed 8/2020	O
ECOC17	GIS Enhancements	190185	0		0.1	Closed 8/2020	O
ECOC18	Replace MV-90 communication bank module	190186	0	17.6	1.8	Closed 12/2020	O
ECOC19	Move e-Intake estimating functionality into GI	180139	0	30.6	8.6	Closed 12/2020	O
ECOC20	Generator Interconnection Database	190189	0		-0.1	Closed 8/2020	O
ECOC22	Two Way Radio Replacements	180125	0		0	Closed 1/2020	O
ECOC23	Purchase Radio Recording System	180136	0	26	0	Closed 1/2020	O
		Sub-Totals:	0	2,717.20	1,762.60		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	DISTRIBUTION ELECTRIC						
DABC00	Overhead Line Extensions		39.3		27.6	Active	C
DABC01	Single Phase OH Primary Line Extens. 28	200176	0		17.6	Closed 12/2020	
DABC02	Single Phase OH Line Ext. Dover Rd, Ch	200177	0	12.5	10.3	Closed 12/2020	
DABC03	Single Phase OH Line Ext 116 Mountain	200181	0	16.9	6.2	Closed 12/2020	
DABC04	Single Phase OH Line Ext. 190 Manchest	200183	0	13.6	-3.4	Active	
DABC05	Single Phase OH Line Ext. 13 Knowlton F	200190	0	27	-1	Active	
DABC06	Relocation of 5 Utility Poles 87 White Ro	200193	0	7.1	-2.1	Active	
DACC00	Overhead Line Extensions - Carryover		4.9		38.8	Completed 11/2020	C
DACC01	OH Line Ext along a public way Vaughn F	190155	0		1.9	Closed 5/2020	
DACC02	Three Phase Line Relocation 72 S Main S	190164	0		0	Closed 11/2020	
DACC03	Single Phase, OH Line Extension 33 Bail	190177	0		0	Closed 1/2020	
DACC04	Single phase, OH line ext 228 Center Rd.	180175	0	12	-19.9	Closed 5/2020	
DACC05	Three Phase OH Line Ext, 56 E Ricker R	190196	0	23	23	Closed 12/2020	
DACC06	Three Phase Overhead Line Ext 3 Merrim	190201	0		33.9	Closed 11/2020	
DBBC00	Underground Line Extensions		99.8		98.7	Active	C
DBBC02	Three Phase URD Line Ext -47 Ryan Rd,	200109	0	6.9	9.2	Closed 12/2020	
DBBC03	Single Phase URD Line Extension 105 W	200122	0		10.9	Closed 11/2020	
DBBC04	Relocate EL Infrastructure for Pedestrian	200148	0		-7.7	Closed 11/2020	
DBBC05	Single Phase URD Line Ext. Hamilton Ct.	200149	0		41.4	Closed 11/2020	
DBBC06	Three Phase URD Line Ext. 1912 Dover I	200150	0	50.1	-24.5	Active	
DBBC07	Three Phase PrimaryURD Line Ext 63 Bo	200161	0		21.7	Closed 11/2020	
DBBC08	New Primary UG Line Ext to Feed Site Li	200171	0	14.2	10.2	Closed 12/2020	
DBBC09	Single Phase URD Line Ext 35 Howards	200172	0	4.7	-5.6	Active	
DBBC10	Replace Pole to accomodate Primary UR	200173	0	19.5	32.1	Completed 8/2020	
DBBC11	Three Phase Primary URD Line Ext. 212	200166	0	39.1	39.8	Closed 12/2020	

CONSTRUCTION BUDGET 2020 UES Capital

12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DBBC12	Single Phase URD Line Extension Welch	200175	0	15.3	-15.4	Active	
DBBC13	3 PH URD Line Extension Primary 10 Do	200179	0	23.1	18.1	Closed 12/2020	
DBBC14	Single Phase URD Primary Line Ext. 129	200186	0	21.4	-4.3	Active	
DBBC15	Three Phase URD Line Extension-5 Tallw	200188	0	14.4	-5	Active	
DBBC16	Three Phase URD Line Ext 149 East Side	200196	0	41.8	-22.3	Active	
DBCC00	Underground Line Extensions, Carryover		23.6		109.2	Completed 8/2020	C
DBCC01	Three Phase URD Line Ext-1 Minuteman	190150	0		0	Closed 2/2020	
DBCC02	Single Phase, URD Line Extension. 226 (	190166	0		0.3	Completed 3/2020	
DBCC03	Three Phase, URD Line Ext. 13 Dunklee	190167	0		3.3	Closed 10/2020	
DBCC04	Single Phase URD Line Extension 15 Mo	190187	0	1.5	4	Closed 5/2020	
DBCC05	Three Phase URD Line Extension - 404 S	190188	0	3.6	-27	Closed 11/2020	
DBCC06	Three Phase UG Primary 89 Fort Eddy R	190193	0		0	Closed 11/2020	
DBCC07	Three Phase, URD Line Ext., 250 Pleasa	180167	0	32.6	-17.3	Closed 11/2020	
DBCC08	Three Phase, URD Line Ext., 285-287 Lo	180169	0		5.9	Cancelled 1/2020	
DBCC09	Single phase, URD LIne Extens. 33 Elkin	180176	0		-3.5	Closed 12/2020	
DBCC10	Three phase URD Line Ext, 25 Sandquist	190194	0		40.9	Closed 11/2020	
DBCC11	Three Phase, URD Line Ext., 660 River F	180174	0	24.3	-3.5	Closed 12/2020	
DBCC12	SINGLE PHASE URD LINE EXT 130 SN	190195	0		1.3	Closed 10/2020	
DBCC13	Three Phase URD Primary Line Ext, 33 C	190197	0	51.5	51.5	Closed 12/2020	
DBCC14	Single Phase Underground Line Ext. Sigr	190199	0		21.8	Closed 10/2020	
DBCC15	Three Phase URD Line Ext -77 Merrimac	180182	0		0	Closed 11/2020	
DBCC16	Single Phase OH/URD Line Ext 135 N St	190200	0		31.6	Closed 11/2020	
DBCC17	Single Phase URD Primary Line Ext. Faw	180179	0	24.6	0	Completed 5/2020	
DCBC00	Street Light Projects		3.7			Active	M
DCCC00	Street Light Projects - Carryover		0.6			Completed 2/2020	M
DDBC00	Telephone Company Requests		15.4			Active	H
DDCC00	Telephone Company Request - Carryover		1.5			Completed 2/2020	H
DEBC00	Highway Projects		71.8		138.2	Active	H
DEBC01	Hooksett Turnpike Rd., Bow - Build Circu	200151	0	49.2	0	Active	
DEBC02	Birchdale Rd., Concord - Pole Relocation	200169	0	62.7	0	Active	
DEBC03	Relocate 15 Poles along Rt3A and Dunkl	200184	0	208.2	138.2	Active	
DECC00	Highway Projects, Carryover		7.2			Completed 2/2020	H
DPBC01	Condemned Poles Distribution	200110	646.8	1,476.50	1,512.20	Active	M
DPBC02	Build Circuit Tie 8X3-8X5 - Sheep Davis Rd.	190144	354.5		0	Completed 1/2020	I
DPBC03	Replace pole, Install Viper recloser and GOA	200157	220.5	220.5	151.9	Active	M
DPBC05	Replace roof with Precast roof	200194	128	229.1	0	Active	M
DPBC06	Install additional phase on Dunbarton Center	200178	177.7	231.5	81.6	Closed 12/2020	M
DPBC07	Conversion in Downtown Concord - Part 2	200124	721.8	721.8	408.6	Active	I
DPBC08	Install Conduit and Primary URD Cable betw	190160	0		20.3	Cancelled 1/2020	M
DPBC88	Condemned Poles Sub-Transmission	200111	0		-6.8	Cancelled 3/2020	M
DPBC89	Condemned Poles Consolidated Maint.	200112	0		-20.3	Cancelled 3/2020	M
DPBC99	Distribution Condemned Poles	210110	0		0	Active	M
DPCC01	Replace Pad mounted switchgear Cir 1H2 ar	190169	328.9	472.9	200.3	Active	M
DPNC01	Wind/Rain Storm - October 17th, 2019	200168	0		76.8	Closed 11/2020	M
DPNC02	N State St., Concord - Replace Conduit and I	200187	0	80.8	41.4	Completed 1/2020	M
DPNC03	Wind Event 7-10-18	180187	0	124	-0.1	Completed 1/2020	M
DPOC01	Condemned Poles Distribution	190112	0		53.5	Closed 11/2020	M
DPOC02	Replace Poles 93/1X and 93/2 and install 3 r	190171	0	52.8	-17.4	Closed 12/2020	M
DPOC03	Replace Man Hole roof with new precast roo	180181	0		44.4	Closed 10/2020	M
DPOC04	Rebuild Low Ave, Concord with Hendrix Con	180172	0		-34.3	Closed 8/2020	M
DPOC05	Re-conductor and re-insulate circuit 1H6	190149	0	250	35.6	Completed 12/2020	I
DPOC06	Porcelain Cutout Replacements	190130	0		11.8	Closed 2/2020	M
DPOC07	Perform Cable rejuvenating fluid injection on	190153	0		0	Closed 8/2020	M
DPOC08	Replace Recloser - Pole 27-1 - Water Street,	190139	0	36.7	0.8	Closed 12/2020	M
DPOC09	Perform Cable rejuvenating fluid injection on	190154	0		0	Closed 10/2020	M
DPOC10	Install three 100 Amp Regulators on P# 354/	190161	0		0	Closed 2/2020	M
DPOC11	Install 3 Regulators on Pole # 33	190168	0		0	Closed 5/2020	I
DPOC12	Install three phase Hendrix	190148	0		-3.5	Closed 8/2020	M
DPOC13	Reconductor 1H6 - Pleasant and Green Stre	190174	0	197.8	32.9	Closed 10/2020	I
DPOC14	Reconductor/Convert Circuit 1H6 - Thompso	190181	0		-7.3	Closed 10/2020	I
DPOC15	Install Step-Down Transformers - Pole 33 - H	190184	0		0	Closed 10/2020	I
DPOC16	Convert 10 sections of Basin Rd to 34.5 KV t	190190	0		65.9	Closed 8/2020	I
DPOC17	Reconductor/Convert Circuit 1H6 - S Spring	190192	0		36.2	Closed 10/2020	I
DPOC18	374 Line Rebuild with 15kV Underbuild	190198	0	1,066.00	787.3	Active	I
DRBC00	Reliability Projects		287.5		386.9	Active	R
DRBC12	Lincoln St., Boscawen - Pole 1 - Install Fu	200152	0		16.3	Closed 11/2020	

Electric Category	2019

Budget Category

CONSTRUCTION BUDGET 2020 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DRBC14	Install Fuse Saver - Stickney Hill Rd., Ho	200153	0		14.2	Closed 10/2020	
DRBC15	Knox Rd., Bow - Pole 56 - Install Fuse Sa	200155	0		17.9	Closed 10/2020	
DRBC16	Install Viper Recloser Main Street, Chich	200156	0	115.3	91.3	Active	
DRBC17	New Orchard Rd., Epsom - Pole 1 - Insta	200154	0		7.9	Closed 10/2020	
DRBC20	Install Viper Recloser on Pleasant St - 6X	200160	0	106.5	49.1	Active	
DRBC27	Install Viper Recloser on Mountain Rd - 1	200158	0	108.8	72.9	Active	
DRBC29	Install Viper Recloser on Regional Dr - 8X	200159	0	112.4	117.3	Active	
DRCC00	Reliabilty Projects, Carryover		0			Completed 6/2020	R
DROC01	Install Recloser & Fuse Saver - Bow Bog Ro	190140	0		0	Completed 7/2020	R
DROC02	Install Animal protection on Distribution Tran	190136	0		0.7	Closed 10/2020	R
DROC03	396X1 Tap - Install Recloser	190119	0		30.1	Closed 11/2020	R
DROC10	Substation Reliability Enhancements at West	180153	0		0	Active	R
DROC12	Install Recloser - Pole 60 - Bow Bog Rd., Bo	180163	0		0	Completed 7/2020	R
		Sub-Totals:	3,133.40	6,424.10	4302.0		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE ELECTRIC						
EAEC01	Purchase and Replace Rubber Goods	200125	5.5	5.5	2.4	Active	O
EAEC02	Purchase and Replace Hot Line Tools	200126	3.5	3.5	9	Active	O
EAEC03	Tools, Shop & Garage - Normal Additions an	200127	14	14	19	Active	O
EAEC04	Normal additions & replacement - tools & eq	200116	7	7	3.8	Active	O
EAEC05	Normal Additions and Replacements - Tools	200130	10	10	9.4	Active	O
EAEC06	Purchase Bierer PD - 50 All purpose Utility M	200128	3		0	Cancelled 6/2020	O
EAEC07	Purchase tools for new Bucket Truck #24		5		0	Active	O
EAEC08	Purchase Bierer PD - 50 All purpose Utility M	200128	12		3	Closed 11/2020	O
EAEC10	Purchase new Dig Safe Locating Machine		4.5			Cancelled 6/2020	O
EAEC12	Purchase Vivaz/Metrotech Pro 2 Dig safe loc	200170	4.3	4.5	3.5	Closed 12/2020	O
		Sub-Totals:	68.8	44.5	50.1		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE GENERAL						
EAOC01	Tools, Shop & Garage - Normal Additions an	170116	0	13.5	0	Closed 2/2020	O
EAOC02	Purchase and Replace Rubber Goods	170117	0	5.5	2	Closed 3/2020	O
EAOC03	Purchase and Replace Hot Line Tools	170118	0	3.3	1.4	Closed 1/2020	O
EAOC04	Normal additions & replacement - tools & eq	190110	0		0	Closed 2/2020	O
EAOC05	Normal Additions and Replacements - Tools	190121	0		0.6	Closed 2/2020	O
EAOC06	Purchase tools for new Bucket Truck # 23	170167	0	5	0	Closed 1/2020	O
EAOC08	Purchase and Replace Rubber Goods	180128	0	5.5	0	Closed 1/2020	O
		Sub-Totals:	0	32.8	4		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	LABORATORY GENERAL						
EBBC01	Lab Equipment - Normal Additions and Repla	200117	7	7	3.8	Active	O
EBOC01	Lab Equipment - Normal Additions and Repla	190111	0		0	Closed 3/2020	O
		Sub-Totals:	7	7	3.8		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE ELECTRIC						
EDEC01	Office Furniture & Equipment-Normal Additio	200120	3.5	3.5	1	Active	O
EDEC02	Furniture Replacements-Year 2 of 2 Year Pr	200121	13	13	0	Active	O
		Sub-Totals:	16.5	16.5	1		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE GENERAL						
EDOC01	Office Furniture and Equipment Replacemen	190122	0		0	Closed 3/2020	O
EDOC02	Furniture Replacements Year 1	190123	0		0	Closed 3/2020	O
		Sub-Totals:	0	0	0		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	STRUCTURES GENERAL						
GPBC01	Normal Improvements to Capital Facility	200118	18	18	21.9	Closed 12/2020	O
GPBC03	Office Finishes Improvements	200119	12	12	14.3	Closed 12/2020	O
GPOC01	Normal Improvements to Capital Facility	190120	0		0	Closed 10/2020	O
GPOC02	Rooftop AC condenser replacement	190138	0		0	Closed 8/2020	O
GPOC04	Office & Systems Furniture Reconfigurations	180122	0	129	0	Closed 1/2020	O
		Sub-Totals:	30	159	36.2		

Electric Category	2019

Budget Category

CONSTRUCTION BUDGET 2020 UES Capital
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	SUBSTATION ELECTRIC						
SPBC01	Various Substations	200131	10	10	12.2	Active	O
SPBC06	Bridge St. Regulator Replacement		271.5			Active	M
SPBC07	Substation Stone Installation at W Portsmout	200132	56	56	36.6	Closed 12/2020	M
SPBC10	Replace 13W2 Circuit Position	210109	253.6		0.0	Active	I
SPCC01	Gulf Street - Outside Services	190118	1,846.70	2,925.00	2422.9	Closed 11/2020	I
SPCC02	West Concord - Replace RTU and Upgrade I	190115	229.1	280	33.1	Active	M
SPNC02	Replace Failed Capacitor Vacuum Switch 4C	200165	0		52.8	Closed 10/2020	M
SPOC01	Replace the 374J5 and the 374J6 Switches	190114	0	182.1	193.4	Closed 12/2020	M
SPOC02	Install Crushed Stone at West Concord S/S	190135	0		0.0	Closed 2/2020	O
SPOC03	Bow Bog - Replace SCADA RTU	190116	0		35.4	Closed 11/2020	O
SPOC04	Hazen Drive - Replace SCADA RTU	190117	0	50.2	7.7	Closed 12/2020	O
SPOC05	Bridge Street - Replace 35KV Line Relaying	180149	0		31.9	Closed 10/2020	O
		Sub-Totals:	2,666.80	3,503.40	2826.0		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TRANSPORTATION ELECTRIC						
FEBC01	#14 - Electric Ops (Mgr) - SUV		0			Active	
FEBC02	#11 - Electric Ops (Line Supv) - Pick Up		0			Active	
FEBC03	#45 - Electrics Ops (Utility Mnt Wrkr) - Pick Up		0			Active	
FEBC04	#15 - Electric Ops (Field Svc Spvsr) - Pick Up		0			Active	
FEBC05	#24 - Electric Ops (Substation) - Line Truck		0			Active	
FEBC06	Forklift (Propane)		0			Active	
FEBC07	Purchase GPS Tracking Devices for Contractor Crews		2.1			Active	
FEBC08	Purchase Substation Work Trailer		0			Active	
		Sub-Totals:	2.1	0			
		Grand Totals:	10,359.70	29,474.00	14057.9		

Electric Category	2019		Budget Category

CONSTRUCTION BUDGET 2020 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	BLANKETS ELECTRIC						
BABE20	Electric & T&D Improvements	201000	1,608.70	1,611.80	1,317.80	Active	M
BABE21	Electric T&D Improvements	211000	0		0.9	Active	M
BACE19	Electric T&D Improvements	181000	0	1,806.60	-33.9	Completed 1/2020	M
BACE20	Electric T & D Improvements	191000	44.2	1,441.50	46.5	Active	M
BAOE17	2015 Electric T&D	151000	0		0.1	Active	M
BAOE18	Electric T&D Improvements	161000	0	1,556.70	-0.7	Closed 1/2020	M
BAOE19	Electric T & D Improvements	171000	0	1,955.00	-0.4	Closed 1/2020	M
BBBE20	New Customer Additions	201001	437.6	487.7	744.3	Active	C
BBBE21	New Customer Additions	211001	0		2	Active	C
BBCE19	NewCustomer Additions	181001	0		0	Closed 1/2020	C
BBCE20	New Customer Additions	191001	17.6	445.7	38.3	Active	C
BBOE19	New Customer Additions	171001	0	559.4	0	Closed 1/2020	C
BCBE20	Outdoor Lighting	201002	182.8	143.7	113.8	Active	M
BCBE21	Outdoor Lighting	211002	0		0	Active	M
BCCE19	Outdoor Lighting	181002	0	240.6	-2.5	Completed 1/2020	M
BCCE20	Outdoor Lighting	191002	10.5	196.4	4.6	Active	M
BCOE18	Outdoor Lighting	161002	0	274.6	0	Active	M
BCOE19	Outdoor Lighting	171002	0	276.8	-0.6	Closed 1/2020	M
BDBE20	Emergency & Storm Restoration	201003	472.4	589	766.3	Active	M
BDBE21	Emergency & Storm Restoration	211003	0		0.2	Active	M
BDCE19	Emergency & Storm Restoration	181003	0	704.5	-81	Completed 1/2020	M
BDCE20	Emergency & Storm Restoration	191003	15.4	520	-1,077.30	Active	M
BDOE18	Emergency & Storm Restoration	161003	0	396.9	0	Closed 1/2020	M
BDOE19	Emergency & Storm Restoration	171003	0	575.2	-5.9	Closed 1/2020	M
BEBE20	Billable Work	201004	404	417.1	484.6	Active	M
BEBE21	Billable Work	211004	0		0.9	Active	M
BECE19	Billable Work	181004	0	410.6	-34.1	Completed 1/2020	M
BECE20	Billable Work	191004	0	325.3	-85.3	Active	M
BEOE17	2015 Billable Work	151004	0		0	Closed 1/2020	M
BEOE18	Billable Work	161004	0	399.7	8.9	Active	M
BEOE19	Billable Work	171004	0		-5.5	Closed 1/2020	M
BFBE20	Transformer Purchases - Company	201005	393.2	393.2	292.5	Active	I
BFBE21	Transformer Purchases - Company Conversi	211005	0		0.1	Active	I
BFCE20	Transformer Purchases - Company	191005	24.4	215.1	1.4	Completed 5/2020	I
BFOE19	Transformer Purchases - Company	181005	0	859.8	0	Closed 1/2020	I
BGBE20	Transformer Purchases - Customer	201006	1,118.50	1,120.80	1,020.40	Active	C
BGBE21	Transformer Purchases - Customer Requirer	211006	0		0	Active	C
BGCE17	2016 Transformer Purchases-Customer	161006	0		-2.1	Active	C
BGCE18	2017 Transformer Purchases - Customer	171006	0	1,154.10	0	Closed 1/2020	C
BGCE19	Transformer Purchases - Customer O/H	181006	0	1,320.70	1.2	Closed 1/2020	C
BGCE20	Transformer Purchases - Customer	191006	138.2	1,250.00	405.1	Completed 5/2020	C
BHBE20	Electric Meter Purchases - Company	201008	332.1	332.2	315.1	Active	M
BHBE21	Electric Meter Purchases - Company Require	211008	0		0	Active	M
BHOE19	Electric Meter - Company	181008	0		0	Closed 4/2020	M
BHOE20	Electric Meter - Company	191008	0	281.2	8.3	Completed 2/2020	M
BIBE20	Electric Meter Purchases - Customer	201007	567.2	567.2	600	Active	C
BIBE21	Electric Meter Purchases - Customer Require	211007	0		0	Active	C
BIOE17	2016 Meter Purchases-Customer	161007	0	315	0	Active	C
BIOE20	Electric Meter - Customer	191007	0	530.8	3.3	Completed 2/2020	C
		Sub-Totals:	5,766.80	23,675.00	4,847.30		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS ELECTRIC						
ECEE01	Two Way Radio Replacements		6			Active	O
		Sub-Totals:	6	0			
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	COMMUNICATIONS GENERAL						
ECOE01	AMI Cell Modem Installations	191039	0		0.8	Closed 10/2020	O
		Sub-Totals:	0	0	0.8		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	DISTRIBUTION ELECTRIC						
DABE00	Overhead Line Extensions - New Projects		29.4		72.2	Active	C
DABE01	Single Phase, Overhead Line Ext., 218 H	161031	0		0	Closed 1/2020	

Electric Category	2019
Growth	
Customer Additions (C)	3,131,600
Subtotal Growth	3,131,600
Non-Growth	
Reliability (R)	449,900
Maintenance Replacement (M)	4,301,800
Mandated (H)	195,400
System Improvement (I)	1,370,000
Grid Modernization (G)	0
Other (O)	13,739,200
Subtotal Non-Growth	20,056,300
Total	23,187,900
	23,187,900
	0

Budget Category	2020
Annual Requirements Blankets	**2020**
T&D Improvements	1,330,300
New Customer Additions	784,600
Outdoor Lighting	115,300
Emergency & Storm Restoration	(397,700)
Billable work	369,500
Transformers	1,718,600
Meters	926,700
Sub-Totals:	**4,847,300**
Distribution	
Overhead Line Extensions over $20,000	74,500
Underground Line Extensions over $20,000	244,600
Street Light Projects	-
Telephone Company Requests	-
Highway Projects	195,400
Distribution Pole Replacements	1,796,400
Specific Projects: Distribution	1,964,000
Sub-Totals:	**4,274,900**
Substation	
Specific Projects: Substation	386,700
Sub-Totals:	**386,700**
Communications	**800**
Tools, Shop, Garage	**54,600**
Laboratory	**6,300**
Office	**300**
Structures	**13,617,000**
Distribution Totals:	**23,187,900**

CONSTRUCTION BUDGET 2020 UES Seacoast
12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
DABE02	Single Phase, Overhead Line Ext., 124 D	201046	0		16.6	Closed 11/2020	
DABE03	Overhead Line Extension & Relocation of	201059	0	10.7	12.6	Active	
DABE04	Single Phase, O/H Line Ext., Brown Rd.,	201064	0		59.8	Closed 11/2020	
DABE05	Three phase, O/H Line Ext., 11 Batchelde	201066	0	22.3	22.1	Closed 10/2020	
DABE06	Three Phase, O/H Line Ext., 19A Batchel	201072	0		2.7	Closed 11/2020	
DABE07	Relocation of Poles, 601 Lafayette Rd., S	201075	0		-41.5	Active	
DACE00	Overhead Line Extensions, Carryover		22.4		2.3	Active	C
DACE01	Three Phase, O/H Line Ext., 31-33 Ocear	151053	0		3.5	Closed 1/2020	
DACE02	Single Phase, Overhead Line Ext., 218 H	151099	0	8.5	-1.2	Closed 10/2020	
DACE03	Three Phase, Overhead Line Ext., 81 Led	191067	0		0	Closed 1/2020	
DACE04	Single Phase, Overhead Line Ext., 53 Hig	171063	0	6	0	Closed 1/2020	
DACE05	Single Phase, O/H Line Ext., 41 Kimball F	191044	0	5.7	0	Closed 1/2020	
DACE06	Three Phase, O/H Line Ext., 137 Folly Mil	181067	0		0	Closed 1/2020	
DBBE00	Underground Line Extensions - New Projects		241		122.5	Active	C
DBBE01	Single Phase, URD Line Ext., Chandler D	191029	0		0	Closed 1/2020	
DBBE02	Single Phase, URD Line Ext., 98 Linden S	191041	0		0	Closed 1/2020	
DBBE03	Install Underground Secondary, 482 High	191045	0		0	Closed 1/2020	
DBBE08	Relocation of Pole & Underground Secon	201036	0		8.9	Closed 10/2020	
DBBE09	Three Phase, URD Line Ext., 24 Whittake	201038	0		16	Closed 11/2020	
DBBE10	Three Phase, URD Line Ext., Little River	201042	0		14.6	Closed 11/2020	
DBBE11	Single Phase, URD Line Ext., off Pine St.	201043	0	60.3	66.9	Closed 12/2020	
DBBE22	Three Phase, URD Line Ext., Ray Farms	201047	0		13.6	Closed 10/2020	
DBBE23	Single Phase, URD Line Ext., 90 Winnicu	201048	0		47.6	Closed 11/2020	
DBBE24	Single Phase, URD Line Ext. Winchester	201052	0		23.7	Closed 10/2020	
DBBE25	Upgrade Three Phase Service, Exeter Pu	201053	0		9.6	Closed 10/2020	
DBBE26	Three Phase, URD Line Ext., 30 Energy W	201054	0		23.3	Closed 11/2020	
DBBE27	Three Phase, URD Line Ext., Main St & R	201056	0		-4.3	Closed 12/2020	
DBBE28	Single Phase, URD Line Ext., off Timbers	201062	0	129.6	-46.9	Active	
DBBE29	Single Phase, URD Line Ext., 230 Mill Rd	201063	0	40.1	42.1	Closed 12/2020	
DBBE30	Pole Relocation & URD Line Ext., 90 Dep	201065	0		-3.1	Closed 12/2020	
DBBE31	Three Phase, URD Line Ext., 152 Drinkw	201067	0	35	-4.4	Active	
DBBE32	Three Phase, URD Line Ext., 431-435 Oc	201069	0	29.3	3.3	Active	
DBBE33	Single Phase, URD Line Ext., off Spruce	201070	0		22.6	Closed 11/2020	
DBBE34	Single Phase, URD Line Ext., Campbell D	201071	0	12	3.5	Closed 12/2020	
DBBE35	Three Phase, URD Line Ext., 601 Lafayet	201073	0	63.9	-93.2	Active	
DBBE36	Three Phase, URD Line Ext., 89 Holland	201074	0	27.2	6.7	Completed 12/2020	
DBBE37	Single Phase, URD Line Ext., 219 Hilldale	201082	0	29.5	6.7	Active	
DBBE39	Single Phase, URD Line Ext., 25 Depot R	201093	0	12.8	-16.2	Active	
DBBE40	Three Phase, URD Line Ext., 537 Ocean	201094	0	20.1	-18.3	Active	
DBCE00	Underground Line Extensions, Carryovers		310		122.1	Active	C
DBCE01	Single Phase, URD Line Ext., Ward Way,	191072	0		46.9	Closed 7/2020	
DBCE02	Three Phase, URD Line Ext., 700 Lafayet	191046	0		6.8	Closed 5/2020	
DBCE03	Single Phase, URD Line Ext., Old County	191047	0		0	Closed 1/2020	
DBCE04	Single Phase, URD Line Ext, 236 Winnac	191050	0	26.4	-3.6	Completed 1/2020	
DBCE05	Three Phase, URD Line Ext., 315 Ocean	191056	0	19	22	Completed 12/2020	
DBCE06	Single Phase, URD Line Ext., Heritage La	191061	0		26.1	Closed 10/2020	
DBCE07	Single Phase, URD Line Ext., 69 Main St.	191062	0	10.3	17.8	Closed 12/2020	
DBCE08	Three Phase, URD Line Ext., 127 Plaistow	191063	0		-24.5	Closed 10/2020	
DBCE09	Three Phase, URD Line Ext, Main St., Kir	181041	0		-1.2	Closed 1/2020	
DBCE10	Three Phase, URD Line Ext., 29 Academ	171047	0		0	Closed 1/2020	
DBCE11	Three Phase, URD Line Ext., 60 Portsmo	191070	0	13	16.4	Closed 12/2020	
DBCE12	Three Phase, URD Line Ext., 82 Newton	191055	0		0	Closed 1/2020	
DBCE13	Three Phase, URD Line Ext., Mill Rd., Ha	181040	0		6.3	Closed 10/2020	
DBCE14	Single Phase, URD Line Ext., 199 South	171026	0		9.1	Closed 11/2020	
DBCE15	Single Phase and Three Phase, URD Lin	181029	0		0	Active	
DBOE02	Three Phase, URD Line Ext., 277 Water St, E	171054	0		0	Active	C
DCBE00	Street Light Projects		26.4			Active	M
DCCE00	Street Light Projects, Carryover		0			Active	M
DDBE00	Telephone Company Requests		0			Active	H
DDCE00	Telephone Company Requests, Carryover		0			Active	H
DEBE00	Highway Projects		196.3		195.4	Active	H
DEBE01	Relocation of 19 Poles and Anchors, Vari	201049	0		147.1	Closed 11/2020	
DEBE02	Relocation of Pole, West Main St., & Pea	201058	0		48.3	Closed 10/2020	
Dec-00	Highway Projects, Carryover		0		0	Active	H
DECE01	Relocation of Poles, Epping Road, Exeter	181057	0		0	Closed 1/2020	
DPBE01	Distribution Pole Replacements	211010	1,071.60		1,361.00	Active	M

Electric Category	2019

Budget Category

CONSTRUCTION BUDGET 2020 UES Seacoast

12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTEI AMOUNT	PROJECT STATUS	Electric Category
DPBE03	Transfer Circuit 19H1 to Circuit 27X1, Drinkw	201032	226.9		358.5	Closed 11/2020	I
DPBE04	Circuit 23X1 Install Stepdowns and Add Prim	211012	45.2		49.1	Closed 10/2020	I
DPBE05	15X1 - Upgrade Stepdown Transformer	211009	42.7		41.6	Closed 11/2020	I
DPBE06	Circuit 58X1 - Convert Main Street, Plaistow	201068	373.7	425	96.6	Active	I
DPBE07	Circuit 6W1, Convert Jewell St, South Hampt	211013	72.3		23.3	Active	I
DPBE08	Replace Eight (8) H-Structures on the 3348 &	201041	461.1		351.7	Active	M
DPBE12	Porcelain Cutout Replacements, Various Loc	211011	0		0	Active	M
DPBE13	Circuit 47X1, Stratham - Add SCADA to 47X1	201087	8.9	8.9	0	Active	M
DPBE14	Circuit 13W1, Convert Kelley Road, Plaistow	201024	149.3		105.2	Closed 11/2020	I
DPBE16	Circuit 56X1 - Convert Route 125, Kingston	201034	224.9	562.7	0	Active	I
DPBE20	Distribution Pole Replacements	201009	0	1,416.60	83.6	Active	M
DPBE88	Replace Eight (8) H-Structures on the 3348 &	201041	0	461.1	0	Active	M
DPCE01	Establish 5X3/58X1 Distribution Circuit Tie, M	191025	41.1		32	Closed 11/2020	I
DPCE04	Convert Portion of 43X1 to 6W2, Main St anc	181051	0		0	Closed 1/2020	I
DPCE06	Circuits 5H1/5H2 - Transfer to 5X3, Witch La	181050	0		0	Closed 1/2020	I
DPNE01	Wind Storm - February 25th, 2019	201050	0	46.4	46.4	Closed 11/2020	M
DPNE02	Wind/Rain Storm - October 17th, 2019	201051	0	168.4	168.8	Closed 12/2020	M
DPNE03	Replace Damaged 18X1R2 Recloser, Timbe	201088	0	65	24.2	Active	M
DPNE04	Upgrade Poles and Stepdown Transformers,	201090	0		50.9	Closed 11/2020	I
DPNE05	Circuit 3W4, Upgrade Stepdown Transforme	201091	0	49	0	Active	I
DPNE06	Circuit 21W1, Extend primary to Improve Vol	201092	0	45	0	Active	I
DPNE08	Wind/Snow Storm - March 7, 2018	181062	0		0.1	Closed 1/2020	M
DPOE01	Porcelain Cutout Replacements, Various Loc	191022	0	327.4	213.4	Active	M
DPOE02	Circuit 3H1 - Convert to 13.8 kV, Ocean Blvd	181052	0		44.8	Closed 11/2020	I
DPOE03	Replace 3347A and 3347B Reclosers at 3347	181042	0		0	Closed 10/2020	M
DPOE04	Distribution work for PV facility at 199 South	191042	0		11.4	Closed 12/2020	M
DPOE05	Convert and Transfer Portion of 5X3 to 13W1	191065	0		41	Closed 2/2020	I
DPOE06	Kingston S/S AMI Equip - TS2 to PLX	181058	0		8.4	Closed 2/2020	M
DPOE07	Circuit 6W1 - Convert Chase Road, South Ha	191068	0		198.4	Closed 5/2020	I
DPOE10	Replace Structure 2044 on 3348 Sub-Transm	181061	0		0.1	Active	M
DRBE00	Reliability Projects		323.6		232.2	Active	R
DRBE05	Install Reclosers on the 3354 & 3343 Sub	201040	0	240	194.2	Active	
DRBE07	Install Reclosers and Implement Distribut	201061	0	375	38	Active	
DRCE00	Reliability Projects, Carryover		311.3		272.9	Active	R
DRCE01	Circuit 13W2, Install Reclosers, Various L	191058	256.7	250	222.4	Completed 12/2020	
DRCE02	Circuit 19X2 - Distribution Automation Sc	191040	0	205.3	50.5	Active	
DROE01	Install Electronic Recloser, Little River Rd., H	191033	0		1.3	Closed 5/2020	R
DROE02	3346 Line - Automatic Restoration Scheme	181030	0		-63.2	Closed 2/2020	R
DROE16	Guinea Switching Reliability Enhancements	181046	0		6.7	Closed 2/2020	R
		Sub-Totals:	4,434.90	5,227.40	4,274.90		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTEI AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE ELECTRIC						
EAEE01	Tools, Shop & Garage - Normal Additions an	201015	14.5	14.5	14.6	Active	O
EAEE02	Purchase and Replace Rubber Goods	201016	6	6	4.1	Active	O
EAEE03	Purchase and Replace Hot Line Tools	201017	4.5	4.5	5.9	Active	O
EAEE04	Normal additions & replacement - tools & equ	201012	7	7	6.4	Active	O
EAEE05	Normal Additions and Replacements- Tools a	201025	10	10	9.4	Active	O
EAEE06	Purchase and Replace Tools for New Truck #	201018	7	7	4.1	Active	O
EAEE08	Replace Battery Operated Compression Tool	201019	5.5		6.3	Closed 7/2020	O
EAEE09	Replace FC300 Handhelds		16		0	Active	O
		Sub-Totals:	70.5	49	50.8		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTEI AMOUNT	PROJECT STATUS	
	TOOLS, SHOP, GARAGE GENERAL						
EAOE01	Tools, Shop & Garage - Normal Additions an	191015	0		0.5	Closed 2/2020	O
EAOE02	Purchase and Replace Rubber Goods	191016	0		0	Closed 2/2020	O
EAOE03	Purchase and Replace Hot Line Tools	191017	0	4.5	0	Closed 2/2020	O
EAOE04	Normal additions & replacement - tools & equ	191030	0		0	Closed 3/2020	O
EAOE05	Normal Additions and Replacements- Tools a	191026	0		0	Closed 2/2020	O
EAOE06	Purchase and Replace Tools for New Truck #	191018	0		0.4	Closed 2/2020	O
EAOE07	Purchase Tools for New Back Yard Lift	191019	0		2.9	Closed 10/2020	O
EAOE10	Normal additions & replacement - tools & equ	181010	0		0	Closed 1/2020	O
		Sub-Totals:	0	4.5	3.8		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTEI AMOUNT	PROJECT STATUS	

Electric Category	2019

Budget Category

CONSTRUCTION BUDGET 2020 UES Seacoast

12 MONTHS ACTUAL AND 0 MONTHS ESTIMATED

BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	Electric Category
	LABORATORY GENERAL						
EBBE01	Lab Equipment - Normal Additions and Repl:	201013	7		0	Active	O
EBBE03	Lab Equipment - Normal Additions and Repl:	201013	0	7	6.3	Cancelled 5/2020	O
EBOE01	Lab Equipment - Normal Additions and Repl:	191011	0		0	Closed 2/2020	O
EBOE02	Purchase Meter Shop Test Station	191012	0	53.5	0	Closed 3/2020	O
		Sub-Totals:	7	60.5	6.3		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE ELECTRIC						
EDEE01	Office Furniture & Equipment – Normal Addit	201023	3.5	3.5	0.3	Active	O
		Sub-Totals:	3.5	3.5	0.3		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	OFFICE GENERAL						
EDOE01	Office Furniture and Equipment Replacemen	191028	0		0	Closed 3/2020	O
		Sub-Totals:	0	0	0		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	STRUCTURES GENERAL						
GPBE01	Normal Improvements to Seacoast DOC Fac	201014	8	8	0.3	Active	O
GPCE01	Acquisition of New DOC & Sale of Existing D	181054	0		0	Cancelled 5/2020	O
GPCE03	Legal . Insurance, Permitting & Misc	191060	10,000.00	15,931.50	13,585.00	Active	O
GPOE01	Normal Improvements to Seacoast DOC Fac	191027	0		0	Closed 10/2020	O
GPOE02	Acquisition of New DOC & Sale of Existing D	191035	0	1,200.00	31.7	Active	O
GPOE03	Plaistow Garage - Roof improvements	191043	0		0	Closed 2/2020	O
		Sub-Totals:	10,008.00	17,139.50	13,617.00		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	SUBSTATION ELECTRIC						
SPBE01	Substation Stone Installation, Various Locatic	201026	36.1	36.1	12.2	Completed 12/2020	O
SPBE03	Mill Lane Multi-Drop Replacement	201057	48.8	48.8	36.8	Completed 11/2020	O
SPBE04	Guinea Substation, Hampton - Upgrade Site	201055	78.5	78.5	11.2	Active	O
SPBE06	Kingston - Modifications & Additions	191071	0	56.3	28.1	Completed 11/2020	I
SPNE01	Replace Failed RTU at Westville	201078	0	47.5	13.9	Active	M
SPNE03	Replace Failed BT-3A Switch at Hampton Be	201080	0		39	Closed 11/2020	M
SPNE04	Replace Failed PT at Guinea S/S	201081	0		50.3	Closed 11/2020	M
SPNE05	Replace failed RTU at Hampton	201084	0		32.1	Closed 11/2020	M
SPNE06	Replaced Failed Regulator on 47X1	201085	0		43.3	Closed 11/2020	M
SPNE07	Replace Failed Regulator & Bypass/DX Swit	201086	0		42.9	Closed 11/2020	M
SPNE08	Replace Remaining Multi-Drop Telephone La	201089	0	110	3	Active	M
SPOE01	Kingston Substation-System Supply	13184	0	12,705.60	0.3	Closed 10/2020	I
SPOE02	Install Crushed Stone at Mill Lane Tap	191037	0		63.4	Closed 2/2020	M
SPOE03	Replace Fence at Timberlane S/S	191038	0		1.8	Closed 2/2020	M
SPOE04	Replace Substation Locks	191021	0		0	Closed 10/2020	M
SPOE05	Stard Road - Replace SCADA RTU	191023	0	50.2	2.2	Closed 5/2020	M
SPOE06	Hampton Beach - 13kV Additions and other r	181047	0		6.2	Closed 10/2020	I
SPOE07	Replace Fence at Dow's Hill Substation	181024	0		0	Completed 2/2020	M
		Sub-Totals:	163.4	13,132.90	386.7		
BUDGET NUMBER	DESCRIPTION	AUTH NUMBER	BUDGETED AMOUNT	AUTH AMOUNT	PROJECTED AMOUNT	PROJECT STATUS	
	TRANSPORTATION ELECTRIC						
FEBE01	Replace Pick Up Truck #12 - Electric Ops (Prmry Stndb		0			Active	
FEBE02	Replace Pick-up Truck #14 - Electric Ops (2nd Standby)		0			Active	
FEBE03	Replace Bucket Truck #25 - Electric Ops		0			Active	
FEBE04	Purchase New Forklift (Electric)		0			Active	
FEBE05	Replace Wire Reel Trailer #T12 - Electric Ops -		0			Active	
FEBE06	Replace Pole Trailer #T8 - Electric Ops - (Large Pole Tr		0			Active	
FEBE07	Purchase GPS Tracking Devices for Contractor Crews		2.1			Active	
		Sub-Totals:	2.1	0			
		Grand Totals:	20,462.20	59,292.30	23,187.90		

Electric Category	2019

Budget Category

Capital Budget 2021 UES Capital

Code	#	Blankets:Electric		2021	2022	2023	2024	2025	Category
BAB		T&D Improvements		1,166,794	1,189,415	1,402,806	1,411,121	1,485,285	M
BAC		T&D Improvements, Carryover		26,359	27,532	33,415	33,368	35,033	M
BBB		New Customer Additions		401,738	419,379	506,495	515,845	548,486	C
BBC		New Customer Additions, Carryover		42,112	33,102	40,164	39,967	42,128	C
BCB		Outdoor Lighting		103,410	107,039	128,591	128,711	135,288	M
BCC		Outdoor Lighting, Carryover		4,224	4,404	5,337	5,326	5,595	M
BDB		Emergency & Storm Restoration		663,545	670,469	784,617	789,690	832,080	M
BDC		Emergency & Storm Restoration, Carryover		11,306	11,332	13,313	13,371	14,201	M
BEB		Billable work		214,031	219,163	262,793	267,266	282,079	M
BEC		Billable work, Carryover		8,525	8,576	9,985	10,062	10,608	M
BFB		Transformers Company/Conversions		88,611	90,761	104,702	107,281	112,772	I
BFC		Transformers Company/Conversions, Carryover		0	0	0	0	0	I
BGB		Transformer Customer Requirements		746,373	761,551	878,086	904,942	956,308	C
BGC		Transformer Customer Requirements, Carryover		79,772	81,449	93,137	96,242	101,032	C
BHB		Meters Company Requirements		176,203	176,249	199,467	203,077	212,269	M
BIB		Meters Customer Requirements		405,171	467,905	531,000	540,174	558,477	C
			Sub-Totals:	4,138,174	4,268,326	4,993,908	5,066,443	5,331,641	
Code	#	Communications:Electric		2021	2022	2023	2024	2025	
ECE	1	Two Way Radio Replacements		2,500	0	0	0	0	O
ECE	21	Two Way Radio Replacements		0	5,000	0	0	0	O
ECE	22	Field Area Network (Grid Mod)		0	350,000	0	0	0	O
ECE	41	Two Way Radio Replacements		0	0	5,000	0	0	O
ECE	42	Field Area Network (Grid Mod)		0	0	350,000	0	0	O
ECE	61	Two Way Radio Replacements		0	0	0	5,000	0	O
ECE	62	Field Area Network (Grid Mod)		0	0	0	200,000	0	O
ECE	81	Two Way Radio Replacements		0	0	0	0	5,000	O
ECE	82	Field Area Network (Grid Mod)		0	0	0	0	200,000	O
EEC	1	Radio Upgrade Project		175,000	0	0	0	0	O
EEC	2	Upgrade TS2 to PLX Infrastructure Carryover		13,000	0	0	0	0	O
			Sub-Totals:	190,500	355,000	355,000	205,000	205,000	
Code	#	Distribution:Electric		2021	2022	2023	2024	2025	
DAB	20	Overhead Line Extensions		29,709	0	0	0	0	C
DAB	20	Overhead Line Extensions		0	29,163	0	0	0	C
DAB	40	Overhead Line Extensions		0	0	36,510	0	0	C
DAB	60	Overhead Line Extensions		0	0	0	36,172	0	C
DAB	80	Overhead Line Extensions		0	0	0	0	38,707	C
DAC	20	Overhead Line Extensions - Carryover		5,343	0	0	0	0	C
DAC	20	Overhead Line Extensions - Carryover		0	5,328	0	0	0	C
DAC	40	Overhead Line Extensions - Carryover		0	0	6,731	0	0	C
DAC	60	Overhead Line Extensions - Carryover		0	0	0	6,688	0	C
DAC	80	Overhead Line Extensions - Carryover		0	0	0	0	7,139	C
DBB	20	Underground Line Extensions		203,057	0	0	0	0	C
DBB	20	Underground Line Extensions		0	208,709	0	0	0	C
DBB	40	Underground Line Extensions		0	0	267,783	0	0	C
DBB	60	Underground Line Extensions		0	0	0	272,343	0	C
DBB	80	Underground Line Extensions		0	0	0	0	291,540	C
DBC	20	Underground Line Extensions, Carryover		35,769	0	0	0	0	C
DBC	20	Underground Line Extensions, Carryover		0	35,971	0	0	0	C
DBC	40	Underground Line Extensions, Carryover		0	0	45,305	0	0	C
DBC	60	Underground Line Extensions, Carryover		0	0	0	45,332	0	C
DBC	80	Underground Line Extensions, Carryover		0	0	0	0	48,358	C
DCB	20	Street Light Projects		4,024	0	0	0	0	M
DCB	20	Street Light Projects		0	4,096	0	0	0	M
DCB	40	Street Light Projects		0	0	4,875	0	0	M
DCB	60	Street Light Projects		0	0	0	4,865	0	M
DCB	80	Street Light Projects		0	0	0	0	5,130	M
DCC	20	Street Light Projects - Carryover		633	0	0	0	0	M
DCC	20	Street Light Projects - Carryover		0	641	0	0	0	M
DCC	40	Street Light Projects - Carryover		0	0	762	0	0	M
DCC	60	Street Light Projects - Carryover		0	0	0	760	0	M
DCC	80	Street Light Projects - Carryover		0	0	0	0	799	M
DDB	20	Telephone Company Requests		13,365	0	0	0	0	M
DDB	20	Telephone Company Requests		0	17,310	0	0	0	M
DDB	40	Telephone Company Requests		0	0	20,638	0	0	M
DDB	60	Telephone Company Requests		0	0	0	20,553	0	M
DDB	80	Telephone Company Requests		0	0	0	0	21,660	M
DDC	20	Telephone Company Request - Carryover		0	0	0	0	0	M
DDC	20	Telephone Company Request - Carryover		0	1,675	0	0	0	M
DDC	40	Telephone Company Request - Carryover		0	0	2,027	0	0	M
DDC	60	Telephone Company Request - Carryover		0	0	0	2,027	0	M
DDC	80	Telephone Company Request - Carryover		0	0	0	0	2,128	M
DEB	20	Highway Projects		78,378	0	0	0	0	H
DEB	20	Highway Projects		0	79,290	0	0	0	H
DEB	40	Highway Projects		0	0	93,617	0	0	H

Electric Category	2021	2022	2023	2024	2025
Growth					
Customer Additions (C)	1,949,044	2,042,557	2,405,211	2,457,705	2,592,175
Subtotal Growth	1,949,044	2,042,557	2,405,211	2,457,705	2,592,175
Non-Growth					
Reliability (R)	460,939	375,000	375,000	446,457	375,000
Maintenance Replacement (M)	5,523,440	4,575,162	4,568,604	4,144,280	4,267,500
Mandated (H)	107,722	90,338	106,916	764,239	782,460
System Improvement (I)	1,903,451	2,659,532	1,984,344	1,179,531	2,711,194
Grid Modernization (G)	0	1,044,671	2,300,478	2,314,446	5,311,438
Other (O)	833,899	840,385	853,734	865,106	743,025
Subtotal Non-Growth	8,829,451	9,585,088	10,189,076	9,714,059	14,190,617
Total	10,778,495	11,627,645	12,594,287	12,171,764	16,782,792
	10,778,495	11,627,645	12,594,287	12,171,764	16,782,792
	0	0	0	0	0

Budget Category					
Annual Requirements Blankets	**2021**	**2022**	**2023**	**2024**	**2025**
T&D Improvements	1,193,153	1,216,947	1,436,221	1,444,489	1,520,318
New Customer Additions	443,850	452,481	546,659	555,812	590,614
Outdoor Lighting	107,634	111,443	133,928	134,037	140,883
Emergency & Storm Restoration	674,851	681,801	797,930	803,061	846,281
Billable work	222,556	227,739	272,778	277,328	292,687
Transformers	914,756	933,761	1,075,925	1,108,465	1,170,112
Meters	581,374	644,154	730,467	743,251	770,746
Sub-Totals:	**4,138,174**	**4,268,326**	**4,993,908**	**5,066,443**	**5,331,641**
Distribution					
Overhead Line Extensions over $20,000	35,052	34,491	43,241	42,860	45,846
Underground Line Extensions over $20,000	238,826	244,680	313,088	317,675	339,898
Street Light Projects	4,657	4,737	5,637	5,625	5,929
Telephone Company Requests	13,365	18,985	22,665	22,580	23,788
Highway Projects	107,722	90,338	106,916	764,239	782,460
Distribution Pole Replacements	685,200	726,824	885,353	920,026	976,788
Specific Projects: Distribution	4,050,725	2,606,465	1,692,851	3,167,340	6,474,267
Sub-Totals:	**5,135,547**	**3,726,520**	**3,069,751**	**5,240,345**	**8,648,976**
Substation					
Specific Projects: Substation	1,093,974	2,919,799	3,810,128	1,133,476	2,195,675
Sub-Totals:	**1,093,974**	**2,919,799**	**3,810,128**	**1,133,476**	**2,195,675**
Communications	**190,500**	**355,000**	**355,000**	**205,000**	**205,000**
Tools, Shop, Garage	**152,300**	**121,500**	**67,000**	**68,000**	**68,000**
Laboratory	**7,000**	**7,000**	**7,000**	**7,000**	**7,000**
Office	**3,000**	**3,500**	**3,500**	**3,500**	**3,500**
Structures	**58,000**	**226,000**	**288,000**	**448,000**	**323,000**
Distribution Totals:	**10,778,495**	**11,627,645**	**12,594,287**	**12,171,764**	**16,782,792**

Capital Budget 2021 UES Capital								
DEB	60	Highway Projects	0	0	0	732,136	0	H
DEB	80	Highway Projects	0	0	0	0	748,543	H
DEC	20	Highway Projects, Carryover	29,344	0	0	0	0	H
DEC	20	Highway Projects, Carryover	0	11,048	0	0	0	H
DEC	40	Highway Projects, Carryover	0	0	13,299	0	0	H
DEC	60	Highway Projects, Carryover	0	0	0	32,103	0	H
DEC	80	Highway Projects, Carryover	0	0	0	0	33,917	H
DPB	1	Distribution Pole Replacement	685,200	0	0	0	0	M
DPB	2	Porcelain Cutout Replacements	223,010	0	0	0	0	M
DPB	3	37 Line - Reconductor Penacook to Maccoy St Tap	1,041,622	0	0	0	0	I
DPB	4	Replace Direct Buried URD Cable Rocky Point Dr, Bow	87,560	0	0	0	0	M
DPB	5	Perform Cable Injection Fairfield St. Concord	169,738	0	0	0	0	M
DPB	6	Cable Injection - 129 Fisherville Rd, Concord	75,229	0	0	0	0	M
DPB	7	38 Line Spacer Reconductoring	248,476	0	0	0	0	I
DPB	8	Perform Cable Injection on Cambridge Dr. Canterbury	28,404	0	0	0	0	M
DPB	9	Arc Hazard Mitigation - 374X1 Tap	112,556	0	0	0	0	M
DPB	10	Replace 33 Line Structure	160,499	0	0	0	0	M
DPB	11	36 Line River Crossing Replacement	369,534	0	0	0	0	M
DPB	12	38 Line River Crossing Replacement	369,713	0	0	0	0	M
DPB	20	Distribution Unspecified	0	0	0	0	0	I
DPB	21	Distribution Pole Replacement	0	726,824	0	0	0	M
DPB	22	Perform Cable Injection New Meadow Rd. Concord	0	84,140	0	0	0	M
DPB	23	Perform Cable Injection E.Ricker Rd. Chichester	0	27,652	0	0	0	M
DPB	24	Transfer Load from 24H1 to 8H1	0	70,164	0	0	0	I
DPB	25	374X1 Spacer Cable Replacement	0	42,944	0	0	0	M
DPB	26	Replace Direct Buried URD Cable Rocky Point Dr, Bow phase 2	0	144,300	0	0	0	M
DPB	27	Replace Direct Buried Cable - Profile Ave	0	36,026	0	0	0	M
DPB	28	2H2 Spacer Cable Replacement	0	435,151	0	0	0	M
DPB	29	Convert 1H2 and 1H3 for Bridge St Rebuild	0	914,067	0	0	0	I
DPB	30	VVO Implementation - 8X5	0	417,021	0	0	0	G
DPB	31	Electric Vehicle Make Ready Program	0	60,000	0	0	0	G
DPB	40	Distribution Unspecified	0	0	0	0	0	I
DPB	41	Distribution Pole Replacement	0	0	885,353	0	0	M
DPB	42	Replace spacer cable on 8H1	0	0	217,373	0	0	M
DPB	43	VVO Implementation - Bow Junction circuits	0	0	700,478	0	0	G
DPB	44	Electric Vehicle Make Ready Program	0	0	400,000	0	0	G
DPB	60	Distribution Unspecified	0	0	0	1,072,250	0	I
DPB	61	Distribution Pole Replacement	0	0	0	920,026	0	M
DPB	62	15W2 Spacer Cable Replacement	0	0	0	257,119	0	M
DPB	63	Electric Vehicle Make Ready Program	0	0	0	460,000	0	G
DPB	64	VVO Implementation - 6X3	0	0	0	912,671	0	G
DPB	65	VVO Implementation -23T	0	0	0	90,300	0	G
DPB	80	Distribution Unspecified	0	0	0	0	2,598,422	I
DPB	81	Distribution Pole Replacement	0	0	0	0	976,788	M
DPB	82	14X3 Spacer Cable Replacement	0	0	0	0	69,746	M
DPB	83	22W2 Spacer Cable Replacement	0	0	0	0	99,661	M
DPB	86	Electric Vehicle Make Ready Program	0	0	0	0	460,000	G
DPB	87	VVO Implementation - Penacook circuits	0	0	0	0	1,435,719	G
DPB	88	VVO Implementation - Gulf Street circuits	0	0	0	0	1,435,719	G
DPC	1	Extend Brown Hill Rd, Bow - 22W3	354,435	0	0	0	0	O
DPC	2	374 Line Rebuild with 15kV Underbuild	144,071	0	0	0	0	I
DPC	3	Manhole improvements MH 6	204,939	0	0	0	0	M
DRB		Reliabilty Projects	460,939	0	0	0	0	R
DRB	20	Reliability Projects	0	375,000	0	0	0	R
DRB	40	Reliability Projects	0	0	375,000	0	0	R
DRB	60	Reliability Projects	0	0	0	375,000	0	R
DRB	80	Reliability Projects	0	0	0	0	375,000	R
		Sub-Totals:	5,135,547	3,726,520	3,069,751	5,240,345	8,648,976	
Code	#	Tools, Shop, Garage:Electric	2021	2022	2023	2024	2025	
EAE	1	Purchase and Replace Rubber Goods	6,000	0	0	0	0	O
EAE	2	Purchase and Replace Hot Line Tools	4,000	0	0	0	0	O
EAE	3	Tools, Shop & Garage - Normal Additions and Replacements	14,500	0	0	0	0	O
EAE	4	Normal additions & replacement - tools & equipment Metering	7,000	0	0	0	0	O
EAE	5	Normal Additions and Replacements - Tools and Equipment - Substation	12,000	0	0	0	0	O
EAE	7	Purchase OMICRON ARCO Recloser Test Set	31,800	0	0	0	0	O
EAE	8	Purchase Omicron Power Factor Test Set	77,000	0	0	0	0	O
EAE	21	Purchase and Replace Rubber Goods	0	6,000	0	0	0	O
EAE	22	Purchase and Replace Hot Line Tools	0	4,000	0	0	0	O
EAE	23	Tools, Shop & Garage - Normal Additions and Replacements	0	14,500	0	0	0	O
EAE	24	Normal additions & replacement - tools & equipment Metering	0	7,000	0	0	0	O
EAE	25	Normal Additions and Replacements - Tools and Equipment - Substation	0	12,000	0	0	0	O
EAE	26	Tools - Unspecified	0	16,000	0	0	0	O
EAE	27	Purchase Oil Filter Unit	0	56,000	0	0	0	O

Capital Budget 2021 UES Capital

EAE	41	Purchase and Replace Rubber Goods	0	0	6,000	0	0	O
EAE	42	Purchase and Replace Hot Line Tools	0	0	4,500	0	0	O
EAE	43	Tools, Shop & Garage - Normal Additions and Replacements	0	0	15,000	0	0	O
EAE	44	Normal additions & replacement - tools & equipment Metering	0	0	7,000	0	0	O
EAE	45	Normal Additions and Replacements - Tools and Equipment - Substation	0	0	12,000	0	0	O
EAE	46	Tools - Unspecified	0	0	16,500	0	0	O
EAE	47	Purchase tools for new Digger Truck # 31	0	0	6,000	0	0	O
EAE	61	Normal additions & replacement - tools & equipment Metering	0	0	0	7,000	0	O
EAE	62	Normal Additions and Replacements - Tools and Equipment - Substation	0	0	0	12,000	0	O
EAE	63	Purchase and Replace Rubber Goods	0	0	0	6,500	0	O
EAE	64	Purchase and Replace Hot Line Tools	0	0	0	4,500	0	O
EAE	65	Tools, Shop & Garage - Normal Additions and Replacements	0	0	0	15,000	0	O
EAE	66	Tools - Unspecified	0	0	0	16,500	0	O
EAE	81	Normal additions & replacement - tools & equipment Metering	0	0	0	0	7,000	O
EAE	82	Normal Additions and Replacements - Tools and Equipment - Substation	0	0	0	0	12,000	O
EAE	83	Purchase and Replace Rubber Goods	0	0	0	0	6,500	O
EAE	84	Purchase and Replace Hot Line Tools	0	0	0	0	4,500	O
EAE	85	Tools, Shop & Garage - Normal Additions and Replacements	0	0	0	0	15,000	O
EAE	86	Tools - Unspecified	0	0	0	0	16,500	O
		Sub-Totals:	152,300	115,500	67,000	61,500	61,500	
Code	#	Tools, Shop, Garage:General	2021	2022	2023	2024	2025	
EAC	21	Purchase tools for new Bucket trk # 22	0	6,000	0	0	0	O
EAC	61	Purchase tools for new Bucket trk # 21	0	0	0	6,500	0	O
EAC	81	Purchase tools for new Bucket trk # 20	0	0	0	0	6,500	O
		Sub-Totals:	0	6000	0	6500	6500	
Code	#	Laboratory:General	2021	2022	2023	2024	2025	
EBB	1	Lab Equipment - Normal Additions and Replacements	7,000	0	0	0	0	O
EBB	21	Lab Equipment - Normal Additions and Replacements	0	7,000	0	0	0	O
EBB	41	Lab Equipment - Normal Additions and Replacements	0	0	7,000	0	0	O
EBB	61	Lab Equipment - Normal Additions and Replacements	0	0	0	7,000	0	O
EBB	81	Lab Equipment - Normal Additions and Replacements	0	0	0	0	7,000	O
		Sub-Totals:	7,000	7,000	7,000	7,000	7,000	
Code	#	Office:Electric	2021	2022	2023	2024	2025	
EDE	1	Office Furn & Equip - Normal Replacement & Additions	3,000	0	0	0	0	O
EDE	21	Office Furniture & Equipment-Normal Additions and Replacements	0	3,500	0	0	0	O
EDE	41	Office Furniture & Equipment-Normal Additions and Replacements	0	0	3,500	0	0	O
EDE	61	Office Furniture & Equipment-Normal Additions and Replacements	0	0	0	3,500	0	O
EDE	81	Office Furniture & Equipment-Normal Additions and Replacements	0	0	0	0	3,500	O
		Sub-Totals:	3,000	3,500	3,500	3,500	3,500	
Code	#	Structures:General	2021	2022	2023	2024	2025	
GPB	1	Normal Improvements to Capital Facility	18,000	0	0	0	0	O
GPB	3	Electric Vehicle Charging Stations – Capital	40,000	0	0	0	0	O
GPB	21	Normal Improvements to Capital Facility	0	18,000	0	0	0	O
GPB	22	Replace Dock Leveler - Capital	0	18,000	0	0	0	O
GPB	23	Building Intrusion Detection System Installation	0	50,000	0	0	0	O
GPB	24	Capital Fire Alarm System	0	140,000	0	0	0	O
GPB	41	Normal Improvements to Capital Facility	0	0	18,000	0	0	O
GPB	42	Replace Generator - Capital	0	0	120,000	0	0	O
GPB	43	Building Electrical System Replacements	0	0	150,000	0	0	O
GPB	61	Normal Improvements	0	0	0	18,000	0	O
GPB	62	Replace Asphalt Shingle Roof - Capital	0	0	0	30,000	0	O
GPB	63	Improvements to Pole Yard Roadway & Pole Yard	0	0	0	200,000	0	O
GPB	64	Site Lighting and Infrastructure Improvements	0	0	0	200,000	0	O
GPB	81	Window Replacements & Building Envelope Improvements	0	0	0	0	250,000	O
GPB	82	Replace Front Entrance Doors - Capital	0	0	0	0	55,000	O
GPB	83	Normal Improvements	0	0	0	0	18,000	O
		Sub-Totals:	58,000	226,000	288,000	448,000	323,000	
Code	#	Substation:Electric	2021	2022	2023	2024	2025	
SPB	1	Garvins - Replace SCADA RTU	45,555	0	0	0	0	M
SPB	2	Terrill Park - Replace SCADA RTU and Upgrade Equipment	290,233	0	0	0	0	M
SPB	3	Bridge Street Substation Upgrades	0	0	0	0	0	I
SPB	4	Langdon Avenue - Replace SCADA RTU	49,295	0	0	0	0	M
SPB	8	Replace Fence Sections at Langdon, Boscawen and Penacook S/S	68,664	0	0	0	0	O
SPB	9	Iron Works 22W1 Control Replacement	34,159	0	0	0	0	M
SPB	10	Replace 13W2 Circuit Position Regulators	264,346	0	0	0	0	I
SPB	20	Substation Projects, Unspecified	0	0	0	0	0	O
SPB	21	Substation Yard Improvements	0	82,839	0	0	0	O
SPB	22	West Portsmouth Street - Replace RTU and Upgrade Equipment	0	215,042	0	0	0	M
SPB	23	Bow Bog Upgrades	0	120,824	0	0	0	I
SPB	24	Iron Works Road - Transformer High-Side Protection	0	206,664	0	0	0	I
SPB	25	Storrs Street Upgrades	0	351,944	0	0	0	I
SPB	26	ABB PCD Relay & Recloser Replacement Project	0	127,487	0	0	0	M

Capital Budget 2021 UES Capital									
SPB	27	OCB Replacement Project: 0374 Breaker at Bridge St S/S	0	229,602	0	0	0	M
SPB	28	5 MVA Mobile S/S - Upgrade Protective Relaying	0	44,546	0	0	0	O
SPB	29	Form 3A Relay Replacement Project	0	68,093	0	0	0	M
SPB	30	Rebuild Bridge St S/S	0	905,108	0	0	0	I
SPB	31	Install SCADA for VVO (Grid Mod)	0	567,650	0	0	0	G
SPB	40	Substation Projects, Unspecified	0	0	0	0	0	I
SPB	41	Substation Yard Improvements	0	0	133,234	0	0	O
SPB	42	Pleasant Street - Replace RTU and Upgrade Equipment	0	0	190,810	0	0	M
SPB	43	OCB Replacement Project: 0375 Breaker at Bridge St S/S	0	0	257,745	0	0	M
SPB	44	Form 3A Relay Replacement Project	0	0	77,233	0	0	M
SPB	45	ABB PCD Relay & Recloser Replacement Project	0	0	71,464	0	0	M
SPB	46	Install SCADA for VVO (Grid Mod)	0	0	1,200,000	0	0	G
SPB	60	Substation Projects, Unspecified	0	0	0	0	0	I
SPB	61	ABB PCD Relay & Recloser Replacement Project	0	0	0	71,457	0	R
SPB	62	Substation Yard Improvements	0	0	0	133,606	0	O
SPB	63	Form 3A Relay Replacement Project	0	0	0	76,938	0	M
SPB	64	Install SCADA for VVO (Grid Mod)	0	0	0	851,475	0	G
SPB	80	Substation Projects, Unspecified	0	0	0	0	0	I
SPB	81	Substation Yard Improvements	0	0	0	0	136,525	O
SPB	82	Form 3A Relay Replacement Project	0	0	0	0	79,150	M
SPB	83	Install SCADA for VVO (Grid Mod)	0	0	0	0	1,980,000	G
SPC	1	Bow Junction - Transformer High-Side Protection	116,325	0	0	0	0	I
SPC	2	West Concord - Replace RTU and Upgrade Equipment	225,397	0	0	0	0	M
SPC	41	Rebuild Bridge St S/S	0	0	1,879,642	0	0	I
		Sub-Totals:	1,093,974	2,919,799	3,810,128	1,133,476	2,195,675	
Code	#	Transportation:Electric	2021	2022	2023	2024	2025	
FEB	1	Replace pickup truck #48 - Substation	1	0	0	0	0	
FEB	2	Replace pickup truck #54 - Standby	1	0	0	0	0	
FEB	3	Replace Electric fork lift-#3	1	0	0	0	0	
FEB	21	Replace pick up #40 - Meter	0	1	0	0	0	
FEB	22	Replace Bucket Truck #22	0	1	0	0	0	
FEB	23	Replace pick up #54 - Standbyc2nd	0	1	0	0	0	
FEB	41	Replace plow/stockroom vehicle #52	0	0	1	0	0	
FEB	42	Replace pickup #42-Meter Mechanic	0	0	1	0	0	
FEB	43	Replace pickup #41- Meter Mechanic	0	0	1	0	0	
FEB	44	Replace #51 - Plow Truck Substations	0	0	1	0	0	
FEB	45	Replace Digger truck #31	0	0	1	0	0	
FEB	61	Replace pick up #6	0	0	0	1	0	
FEB	62	Replace pick up #55	0	0	0	1	0	
FEB	63	Replace Bucket truck #21	0	0	0	1	0	
FEB	81	Replace pick up #11	0	0	0	0	1	
FEB	82	Replace pick up #15	0	0	0	0	1	
FEB	83	Replace pick up #14	0	0	0	0	1	
FEB	84	Replace bucket truck #20	0	0	0	0	1	
		Totals:	10,778,495	11,627,645	12,594,287	12,171,764	16,782,792	

Capital Budget 2021 UES Seacoast

Code	#	Blankets:Electric	2021	2022	2023	2024	2025	Category
BAB		T&D Improvements	1,606,711	1,632,520	1,923,933	1,944,855	2,043,855	M
BAC		T&D Improvements, Carryover	78,204	45,913	55,339	55,129	57,992	M
BBB		New Customer Additions	494,236	511,304	615,340	625,424	669,476	C
BBC		New Customer Additions, Carryover	19,089	20,140	25,146	24,937	26,432	C
BCB		Outdoor Lighting	149,558	159,237	196,083	195,786	205,079	M
BCC		Outdoor Lighting, Carryover	10,520	10,743	12,699	12,878	13,666	M
BDB		Emergency & Storm Restoration	646,645	654,122	770,850	772,280	813,969	M
BDC		Emergency & Storm Restoration, Carryover	17,728	18,232	21,599	21,981	23,320	M
BEB		Billable work	454,353	455,819	536,232	535,219	564,933	M
BEC		Billable work, Carryover	0	0	0	0	0	M
BFB		Transformers Company/Conversions	66,811	194,524	78,061	78,282	80,008	M
BFC		Transformers Company/Conversions, Carryover	194,521	193,256	214,010	215,185	219,486	M
BGB		Transformer Customer Requirements	1,108,673	1,126,900	1,303,494	1,342,895	1,419,776	C
BGC		Transformer Customer Requirements, Carryover	149,631	133,901	152,548	157,793	165,567	C
BHB		Meters Company Requirements	353,861	343,123	399,989	401,924	419,042	M
BIB		Meters Customer Requirements	531,536	560,133	632,797	642,190	663,044	C
		Sub-Totals:	5,882,077	6,059,867	6,938,120	7,026,758	7,385,645	
Code	**#**	**Communications:Electric**	**2021**	**2022**	**2023**	**2024**	**2025**	
ECE	1	Two Way Radio Replacements	2,500	0	0	0	0	O
ECE	21	Two Way Radio Replacements	0	6,000	0	0	0	O
ECE	22	Field Area Network	0	350,000	0	0	0	O
ECE	41	Two Way Radio Replacements	0	0	6,000	0	0	O
ECE	42	Field Area Network	0	0	350,000	0	0	O
ECE	61	Two Way Radio Replacements	0	0	0	6,000	0	O
ECE	62	Field Area Network	0	0	0	200,000	0	O
ECE	81	Two Way Radio Replacements	0	0	0	0	6,000	O
ECE	82	Field Area Network	0	0	0	0	200,000	O
		Sub-Totals:	2,500	356,000	356,000	206,000	206,000	
Code	**#**	**Distribution:Electric**	**2021**	**2022**	**2023**	**2024**	**2025**	
DAB		Overhead Line Extensions	56,186	0	0	0	0	C
DAB	20	Overhead Line Extensions - New Projects	0	56,285	0	0	0	C
DAB	40	Overhead Line Extensions - New Projects	0	0	74,136	0	0	C
DAB	60	Overhead Line Extensions - New Projects	0	0	0	75,813	0	C
DAB	80	Overhead Line Extensions - New Projects	0	0	0	0	82,841	C
DAC		Overhead Line Extensions, Carryover	23,777	0	0	0	0	C
DAC	20	Overhead Line Extensions, Carryover	0	25,622	0	0	0	C
DAC	40	Overhead Line Extensions, Carryover	0	0	31,355	0	0	C
DAC	60	Overhead Line Extensions, Carryover	0	0	0	31,885	0	C
DAC	80	Overhead Line Extensions, Carryover	0	0	0	0	33,923	C
DBB		Underground Line Extensions	397,458	0	0	0	0	C
DBB	20	Underground Line Extensions - New Projects	0	401,869	0	0	0	C
DBB	40	Underground Line Extensions - New Projects	0	0	516,495	0	0	C
DBB	60	Underground Line Extensions - New Projects	0	0	0	523,612	0	C
DBB	80	Underground Line Extensions - New Projects	0	0	0	0	574,852	C
DBC		Underground Line Extensions, Carryover	330,636	0	0	0	0	C
DBC	20	Underground Line Extensions, Carryovers	0	347,461	0	0	0	C
DBC	40	Underground Line Extensions, Carryovers	0	0	418,861	0	0	C
DBC	60	Underground Line Extensions, Carryovers	0	0	0	425,032	0	C
DBC	80	Underground Line Extensions, Carryovers	0	0	0	0	452,186	C
DCB		Street Light Projects	0	0	0	0	0	M
DCC		Street Light Projects, Carryover	0	0	0	0	0	M
DEB		Highway Projects	210,862	0	0	0	0	H
DEB	20	Highway Projects	0	207,474	0	0	0	H
DEB	40	Highway Projects	0	0	245,675	0	0	H
DEB	60	Highway Projects	0	0	0	248,340	0	H
DEB	80	Highway Projects	0	0	0	0	260,791	H
DEC		Highway Projects, Carryover	0	0	0	0	0	H
DEC	20	Highway Projects, Carryover	0	0	0	0	0	H
DEC	40	Highway Projects, Carryover	0	0	0	0	0	H
DEC	60	Highway Projects, Carryover	0	0	0	0	0	H
DEC	80	Highway Projects, Carryover	0	0	0	0	0	H
DPB	1	Distribution Pole Replacements	865,971	0	0	0	0	M
DPB	2	Reconstruct the 3348/50 Sub-Transmission Lines	5,237,092	0	0	0	0	M
DPB	4	23X1 – Install Stepdowns and Add Primary on New Amesbury Rd/Highland Rd, South Hampton	96,763	0	0	0	0	I
DPB	5	15X1 – Upgrade Stepdown Transformer, Pine St, Seabrook	10,010	0	0	0	0	I
DPB	7	Circuit 6W1 - Convert Jewell St. South Hampton to 8 kV	391,838	0	0	0	0	I

Electric Category	2021	2022	2023	2024	2025
Growth					
Customer Additions (C)	3,111,222	3,183,615	3,770,172	3,849,581	4,088,097
Subtotal Growth	3,111,222	3,183,615	3,770,172	3,849,581	4,088,097
Non-Growth					
Reliability (R)	716,346	375,000	375,000	375,000	375,000
Maintenance Replacement (M)	11,025,194	10,800,614	6,654,392	7,065,312	6,284,094
Mandated (H)	210,862	207,474	245,675	248,340	260,791
System Improvement (I)	927,730	3,167,717	5,279,000	5,683,500	5,810,812
Grid Modernization (G)	0	3,935,306	5,003,559	5,699,054	5,139,237
Other (O)	1,136,475	761,289	569,434	420,006	422,925
Subtotal Non-Growth	14,016,607	19,247,400	18,127,060	19,491,212	18,292,859
Total	17,127,829	22,431,015	21,897,232	23,340,793	22,380,956
	17,127,829	22,431,015	21,897,232	23,340,793	22,380,956
	0	0	0	0	0

Budget Category					
Annual Requirements Blankets	**2021**	**2022**	**2023**	**2024**	**2025**
T&D Improvements	1,684,915	1,678,433	1,979,272	1,999,984	2,101,847
New Customer Additions	513,325	531,444	640,486	650,361	695,908
Outdoor Lighting	160,078	169,980	208,782	208,664	218,745
Emergency & Storm Restoration	664,373	672,354	792,449	794,261	837,289
Billable work	454,353	455,819	536,232	535,219	564,933
Transformers	1,519,636	1,648,581	1,748,113	1,794,155	1,884,837
Meters	885,397	903,256	1,032,786	1,044,114	1,082,086
Sub-Totals:	**5,882,077**	**6,059,867**	**6,938,120**	**7,026,758**	**7,385,645**
Distribution					
Overhead Line Extensions over $20,000	79,963	81,907	105,491	107,698	116,764
Underground Line Extensions over $20,000	728,094	749,330	935,356	948,644	1,027,038
Street Light Projects	-	-	-	-	-
Telephone Company Requests	-	-	-	-	-
Highway Projects	210,862	207,474	245,675	248,340	260,791
Distribution Pole Replacements	865,971	1,082,560	1,267,836	1,294,946	1,357,779
Specific Projects: Distribution	8,140,374	11,304,783	9,357,889	10,867,954	9,344,749
Sub-Totals:	**10,025,264**	**13,426,054**	**11,912,247**	**13,467,582**	**12,107,121**
Substation					
Specific Projects: Substation	605,788	2,495,594	2,610,665	2,560,053	2,601,790
Sub-Totals:	**605,788**	**2,495,594**	**2,610,665**	**2,560,053**	**2,601,790**
Communications	**2,500**	**356,000**	**356,000**	**206,000**	**206,000**
Tools, Shop, Garage	**62,200**	**73,000**	**59,700**	**59,900**	**59,900**
Laboratory	**7,000**	**7,000**	**7,000**	**7,000**	**7,000**
Office	**1,000**	**3,500**	**3,500**	**3,500**	**3,500**
Structures	**542,000**	**10,000**	**10,000**	**10,000**	**10,000**
Distribution Totals:	**17,127,829**	**22,431,015**	**21,897,232**	**23,340,793**	**22,380,956**

Capital Budget 2021 UES Seacoast								
DPB	8	Arc Hazard Mitigation - 27X1 - Trundlebed Road, Kensington	271,587	0	0	0	0	M
DPB	9	Arc Hazard Mitigation - 56X1 - Newton Junction Road, Kingston	271,587	0	0	0	0	M
DPB	10	Arc Hazard Mitigation - 46X1 - Winnacunnet Road Tap, Hampton	271,587	0	0	0	0	M
DPB	11	Arc Hazard Mitigation - 5X3 - Stepdowns, Witch Lane, Plaistow	112,556	0	0	0	0	M
DPB	12	Porcelain Cutout Replacements, Various Locations	229,607	0	0	0	0	M
DPB	20	Distribution Projects, Unspecified	0	1,522,000	0	0	0	I
DPB	21	Distribution Pole Replacements	0	1,082,560	0	0	0	M
DPB	22	Circuit 56X1 - Convert Route 125, Kingston	0	424,123	0	0	0	I
DPB	23	Circuit 6W1 - Convert Main Ave. South Hampton to 8 kV	0	310,540	0	0	0	I
DPB	24	3342 & 3353 Lines - Replace Crossarms	0	355,566	0	0	0	M
DPB	25	20T1 Transformer: Transfer Load to 28X1	0	793,434	0	0	0	I
DPB	26	Circuit 27X1 – Re-conductor Drinkwater Rd	0	117,620	0	0	0	I
DPB	27	VVO Implementation - 19X2, 19X3	0	1,063,651	0	0	0	G
DPB	28	VVO Implementation - 11X - Portsmouth Ave.	0	1,025,805	0	0	0	G
DPB	29	Electric Vehicle Make Ready Program	0	120,000	0	0	0	G
DPB	40	Distribution Projects, Unspecified	0	0	5,279,000	0	0	I
DPB	41	Distribution Pole Replacements	0	0	1,267,836	0	0	M
DPB	43	VVO Implementation - Hampton Beach 3T3	0	0	864,207	0	0	G
DPB	44	VVO Implementation - 58X1	0	0	1,264,711	0	0	G
DPB	45	Electric Vehicle Make Ready Program	0	0	400,000	0	0	G
DPB	46	VVO Implementation - 18X1	0	0	1,174,971	0	0	G
DPB	60	Distribution Projects, Unspecified	0	0	0	5,683,500	0	I
DPB	61	Distribution Pole Replacements	0	0	0	1,294,946	0	M
DPB	62	VVO Implementation - 15X1	0	0	0	675,066	0	G
DPB	64	VVO Implementation - 47X1	0	0	0	546,731	0	G
DPB	65	VVO Implementation - 59X1	0	0	0	1,564,012	0	G
DPB	66	Electric Vehicle Make Ready Program	0	0	0	460,000	0	G
DPB	67	VVO Implementation - 2X2 and 2X3	0	0	0	1,563,645	0	G
DPB	80	Distribution Projects, Unspecified	0	0	0	0	5,810,812	I
DPB	81	Distribution Pole Replacements	0	0	0	0	1,357,779	M
DPB	83	Electric Vehicle Make Ready Program	0	0	0	0	520,000	G
DPB	89	VVO Implementation - High Street circuits	0	0	0	0	1,435,719	G
DPB	90	VVO Implementation - 43X1	0	0	0	0	1,203,218	G
DPC	1	Distribution Pole Replacements	96,587	0	0	0	0	I
DPC	3	Circuit 58X1, Convert Main St, Plaistow	332,532	0	0	0	0	I
DPC	3	Town of Exeter, Sidewalk Installations, Relocate Poles	57,393	0	0	0	0	O
DPC	4	18X1 R2 Recloser Replacement, Timberswamp Rd, Hampton	44,889	0	0	0	0	M
DPC	21	3348/50 Lines - Rebuild	0	5,197,044	0	0	0	M
DRB		Reliabilty Projects	339,657	0	0	0	0	R
DRB	20	Reliability Projects, Unspecified	0	375,000	0	0	0	R
DRB	40	Reliability Projects, Unspecified	0	0	375,000	0	0	R
DRB	60	Reliability Projects, Unspecified	0	0	0	375,000	0	R
DRB	80	Reliability Projects, Unspecified	0	0	0	0	375,000	R
DRC	1	Circuit 43X1 – Install Reclosers and Implement Distribution Automation	350,011	0	0	0	0	R
DRC	2	Circuit 19X2 - Distribution Automation Scheme with Portsmouth Ave	26,678	0	0	0	0	R
		Sub-Totals:	10,025,264	13,426,054	11,912,247	13,467,582	12,107,121	
Code	#	Tools, Shop, Garage:Electric	2021	2022	2023	2024	2025	
EAE	1	Tools, Shop & Garage – Normal Additions and Replacements	14,500	0	0	0	0	O
EAE	2	Purchase and Replace Rubber Goods	6,000	0	0	0	0	O
EAE	3	Purchase and Replace Hot Line Tools	4,500	0	0	0	0	O
EAE	4	Normal additions & replacement - tools & equipment Meter and Services	7,000	0	0	0	0	O
EAE	5	Normal Additions and Replacements- Tools and Equipment Substation	12,000	0	0	0	0	O
EAE	6	Purchase Power Back	3,200	0	0	0	0	O
EAE	21	Tools, Shop & Garage – Normal Additions and Replacements	0	14,700	0	0	0	O
EAE	22	Purchase and Replace Rubber Goods	0	6,100	0	0	0	O
EAE	23	Purchase and Replace Hot Line Tools	0	4,700	0	0	0	O
EAE	24	Normal additions & replacement - tools & equipment Meter and Services	0	7,000	0	0	0	O
EAE	25	Normal Additions and Replacements- Tools and Equipment Substation	0	12,000	0	0	0	O
EAE	26	Tools - Line Department, Unspecified	0	15,000	0	0	0	O
EAE	27	Purchase and Replace Tools for New Truck #2	0	7,500	0	0	0	O
EAE	28	Purchase and Replace Tools for New Truck #11	0	6,000	0	0	0	O
EAE	41	Tools, Shop & Garage – Normal Additions and Replacements	0	0	14,800	0	0	O
EAE	42	Purchase and Replace Rubber Goods	0	0	6,100	0	0	O
EAE	43	Purchase and Replace Hot Line Tools	0	0	4,800	0	0	O
EAE	44	Normal additions & replacement - tools & equipment Meter and Field Services	0	0	7,000	0	0	O
EAE	45	Normal Additions and Replacements- Tools and Equipment Substation	0	0	12,000	0	0	O
EAE	46	Tools - Line Department, Unspecified	0	0	15,000	0	0	O
EAE	61	Tools, Shop & Garage – Normal Additions and Replacements	0	0	0	14,800	0	O

Capital Budget 2021 UES Seacoast

EAE	62	Purchase and Replace Rubber Goods	0	0	0	6,200	0	O
EAE	63	Purchase and Replace Hot Line Tools	0	0	0	4,900	0	O
EAE	64	Normal additions & replacement - tools & equipment Meter and Services	0	0	0	7,000	0	O
EAE	65	Normal Additions and Replacements- Tools and Equipment Substation	0	0	0	12,000	0	O
EAE	66	Tools - Line Department, Unspecified	0	0	0	15,000	0	O
EAE	69	Purchase Toolng for New Bucket Truck	15,000	0	0	0	0	O
EAE	81	Tools, Shop & Garage – Normal Additions and Replacements	0	0	0	0	14,800	O
EAE	82	Purchase and Replace Rubber Goods	0	0	0	0	6,200	O
EAE	83	Purchase and Replace Hot Line Tools	0	0	0	0	4,900	O
EAE	84	Normal additions & replacement - tools & equipment Meter and Services	0	0	0	0	7,000	O
EAE	85	Normal Additions and Replacements- Tools and Equipment Substation	0	0	0	0	12,000	O
EAE	86	Tools - Line Department, Unspecified	0	0	0	0	15,000	O
		Sub-Totals:	62,200	73,000	59,700	59,900	59,900	
Code	#	Laboratory:General	2021	2022	2023	2024	2025	
EBB	1	Lab Equipment - Normal Additions and Replacements	7,000	0	0	0	0	O
EBB	21	Lab Equipment - Normal Additions and Replacements	0	7,000	0	0	0	O
EBB	41	Lab Equipment - Normal Additions and Replacements	0	0	7,000	0	0	O
EBB	61	Lab Equipment - Normal Additions and Replacements	0	0	0	7,000	0	O
EBB	81	Lab Equipment - Normal Additions and Replacements	0	0	0	0	7,000	O
		Sub-Totals:	7,000	7,000	7,000	7,000	7,000	
Code	#	Office:Electric	2021	2022	2023	2024	2025	
EDE	1	Office Furniture & Equipment – Normal Additions & Replacements	1,000	0	0	0	0	O
EDE	21	Office Furniture & Equipment – Normal Additions and Replacements	0	3,500	0	0	0	O
EDE	41	Office Furniture & Equipment – Normal Additions and Replacements	0	0	3,500	0	0	O
EDE	61	Office Furniture & Equipment – Normal Additions and Replacements	0	0	0	3,500	0	O
EDE	81	Office Furniture & Equipment – Normal Additions and Replacements	0	0	0	0	3,500	O
		Sub-Totals:	1,000	3,500	3,500	3,500	3,500	
Code	#	Structures:General	2021	2022	2023	2024	2025	
GPB	1	Normal Improvements to Seacoast DOC Facilities	7,500	0	0	0	0	O
GPB	2	Plaistow Garage Improvements	27,000	0	0	0	0	O
GPB	21	Normal Improvements to Seacoast DOC Facility	0	10,000	0	0	0	O
GPB	41	Normal Improvements to Seacoast Facility	0	0	10,000	0	0	O
GPB	61	Normal Improvements to Seacoast DOC Facility	0	0	0	10,000	0	O
GPB	81	Normal Improvements to Seacoast DOC Facility	0	0	0	0	10,000	O
GPC	1	Construct New NH Seacoast Region Facility, Carryover	500,000	0	0	0	0	O
GPC	2	Sale of Kensington DOC Facility, Carryover	7,500	0	0	0	0	O
		Sub-Totals:	542,000	10,000	10,000	10,000	10,000	
Code	#	Substation:Electric	2021	2022	2023	2024	2025	
SPB	1	Replace Fence at Gilman Lane Substation	83,628	0	0	0	0	O
SPB	2	High Street Substation, Hampton - Replace 17W1 & 17W2 Relays	52,094	0	0	0	0	M
SPB	4	Guinea Substation, Hampton - Install Time Keeping System	13,916	0	0	0	0	O
SPB	5	Munt Hill Substation - Replace 28X1 Recloser	64,086	0	0	0	0	M
SPB	7	Rebuild Mill Lane Tap	257,557	0	0	0	0	O
SPB	8	Substation Stone Installation, Various Locations	49,295	0	0	0	0	O
SPB	21	Substation Yard Improvements	0	119,961	0	0	0	O
SPB	22	Exeter Substation, Replace Fence	0	82,839	0	0	0	O
SPB	23	OCB Replacement Project: 3342 Breaker at Guinea Switching S/S	0	296,422	0	0	0	M
SPB	24	Hampton Substation - Replace 2X2 & 2X3 Recloser	0	127,487	0	0	0	M
SPB	25	Form 3A Relay Replacement Project	0	34,046	0	0	0	M
SPB	26	Install SCADA for VVO (Grid Mod)	0	1,725,850	0	0	0	G
SPB	41	Substation Yard Improvements	0	0	133,234	0	0	O
SPB	42	Guinea - Replace EM Relaying	0	0	703,181	0	0	M
SPB	43	ABB PCD Relay & Recloser Replacement Project	0	0	142,928	0	0	M
SPB	45	OCB Replacement Project: 3359 Breaker at Guinea Switching S/S	0	0	331,652	0	0	M
SPB	47	Install SCADA for VVO (Grid Mod)	0	0	1,299,670	0	0	G
SPB	61	Substation Yard Improvements	0	0	0	133,606	0	O
SPB	62	OCB Replacement Project: 3343 Breaker at Guinea Switching S/S	0	0	0	331,931	0	M
SPB	63	ABB PCD Relay & Recloser Replacement Project	0	0	0	142,914	0	M
SPB	64	Install SCADA for VVO (Grid Mod)	0	0	0	889,600	0	G
SPB	81	Substation Yard Improvements	0	0	0	0	136,525	O
SPB	82	ABB PCD Relay & Recloser Replacement Project	0	0	0	0	146,360	M
SPB	83	OCB Replacement Project: 3354 Breaker at Guinea Switching S/S	0	0	0	0	338,605	M
SPB	84	Install SCADA for VVO (Grid Mod)	0	0	0	0	1,980,300	G
SPC	2	Replace Remaining Multi-Drop Telephone Landline Services	59,986	0	0	0	0	O
SPC	6	Westville Substation, Plaistow - Replace SCADA RTU	25,226	0	0	0	0	M
SPC	21	Rebuild Mill Lane Tap	0	108,989	0	0	0	O
SPC	61	Guinea - Replace EM Relaying	0	0	0	1,062,002	0	M
		Sub-Totals:	605,788	2,495,594	2,610,665	2,560,053	2,601,790	

Capital Budget 2021 UES Seacoast							
Code	#	Transportation:Electric	2021	2022	2023	2024	2025
FEB	1	Replace Pick up Truck #26 - Metering	1	0	0	0	0
FEB	2	Replace Pick Up Truck #30	1	0	0	0	0
FEB	3	Replace Pick Up Truck #24	1	0	0	0	0
FEB	21	Replace substation truck #5	0	1	0	0	0
FEB	22	Replace pick up #16	0	1	0	0	0
FEB	24	Replace pick up #34	0	1	0	0	0
FEB	25	Replace Digger Truck #11	0	1	0	0	0
FEB	31	Purchase New Bucket Truck	1	0	0	0	0
FEB	41	Replace Pick Up Truck #18- Project Leader	0	0	1	0	0
FEB	42	Replace Pick Up Truck #15-Field Services Supervisor	0	0	1	0	0
FEB	43	Replace Pick Up Truck #31 - Stock Room/Plow Truck	0	0	1	0	0
FEB	61	Replace pick up #3	0	0	0	1	0
FEB	62	Replace pick up #4	0	0	0	1	0
FEB	63	Replace pick up #7	0	0	0	1	0
FEB	64	Replace pick up #36	0	0	0	1	0
FEB	81	Replace Pick Up Truck #22 - Substation	0	0	0	0	1
FEB	82	Replace pick up #35-Line supervisor	0	0	0	0	1
		Totals:	17,127,829	22,431,015	21,897,232	23,340,793	22,380,956

	Capital Budget Spending															
	Actual											Forecast				
Electric Category	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Growth																
Customer Additions (C)	2,928,000	3,197,600	3,599,600	3,754,100	4,227,000	3,612,300	4,030,800	4,496,900	5,924,000	5,450,400	5,682,300	5,060,266	5,226,172	6,175,383	6,307,286	6,680,272
Subtotal Growth	2,928,000	3,197,600	3,599,600	3,754,100	4,227,000	3,612,300	4,030,800	4,496,900	5,924,000	5,450,400	5,682,300	5,060,266	5,226,172	6,175,383	6,307,286	6,680,272
Non-Growth																
Reliability (R)	484,700	316,000	821,000	594,800	137,300	608,900	346,100	667,000	740,000	920,500	867,600	1,177,285	750,000	750,000	821,457	750,000
Maintenance Replacement (M)	6,707,400	6,586,800	3,960,400	6,491,000	7,063,200	7,307,400	6,359,800	8,823,800	8,617,600	11,149,200	9,048,800	16,548,634	15,375,776	11,222,996	11,209,592	10,551,594
Mandated (H)	-87,400	828,100	409,700	30,900	251,800	1,014,600	1,361,200	154,900	582,400	23,500	333,600	318,584	297,812	352,591	1,012,579	1,043,251
System Improvement (I)	2,115,300	3,216,300	2,103,000	4,509,100	5,626,700	9,595,700	10,692,900	6,106,700	967,900	4,509,900	5,629,400	2,831,181	5,827,249	7,263,344	6,863,031	8,522,006
Grid Modernization (G)								0	0	0	0	0	4,979,977	7,304,037	8,013,500	10,450,675
Other (O)	1,291,300	2,396,000	2,072,600	791,900	2,224,200	1,266,900	396,900	3,500,100	1,455,200	7,015,300	15,684,100	5,650,327	5,069,579	3,909,635	3,925,711	3,467,395
Subtotal Non-Growth	10,511,300	13,343,200	9,366,700	12,417,700	15,303,200	19,793,500	19,156,900	19,252,500	12,363,100	23,618,400	31,563,500	26,526,011	32,300,393	30,802,603	31,845,870	34,784,921
Total	13,439,300	16,540,800	12,966,300	16,171,800	19,530,200	23,405,800	23,187,700	23,749,400	18,287,100	29,068,800	37,245,800	31,586,277	37,526,565	36,977,986	38,153,156	41,465,193
							23,187,700									
% Growth	22%	19%	28%	23%	22%	15%	17%	19%	32%	19%	15%	16%	14%	17%	17%	16%
% Non-Growth	78%	81%	72%	77%	78%	85%	83%	81%	68%	81%	85%	84%	86%	83%	83%	84%

	Low	High
% Growth	15%	32%
% Non-Growth	68%	85%

	Capital Budget Spending															
	Actual											Forecast				
Electric Category	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Growth																
Customer Additions (C)	2,928	3,198	3,600	3,754	4,227	3,612	4,031	4,497	5,924	5,450	5,682	5,060	5,226	6,175	6,307	6,680
Subtotal Growth	2,928	3,198	3,600	3,754	4,227	3,612	4,031	4,497	5,924	5,450	5,682	5,060	5,226	6,175	6,307	6,680
Non-Growth																
Reliability (R)	485	316	821	595	137	609	346	667	740	921	868	1,177	750	750	821	750
Maintenance Replacement (M)	6,707	6,587	3,960	6,491	7,063	7,307	6,360	8,824	8,618	11,149	9,049	16,549	15,376	11,223	11,210	10,552
Mandated (H)	-87	828	410	31	252	1,015	1,361	155	582	24	334	319	298	353	1,013	1,043
System Improvement (I)	2,115	3,216	2,103	4,509	5,627	9,596	10,693	6,107	968	4,510	5,629	2,831	5,827	7,263	6,863	8,522
Grid Modernization (G)	0	0	0	0	0	0	0	0	0	0	0	0	4,980	7,304	8,014	10,451
Other (O)	1,291	2,396	2,073	792	2,224	1,267	397	3,500	1,455	7,015	15,684	5,650	5,070	3,910	3,926	3,467
Subtotal Non-Growth	10,511	13,343	9,367	12,418	15,303	19,794	19,157	19,253	12,363	23,618	31,564	26,526	32,300	30,803	31,846	34,785
Total	13,439	16,541	12,966	16,172	19,530	23,406	23,188	23,749	18,287	29,069	37,246	31,586	37,527	36,978	38,153	41,465
% Growth	22%	19%	28%	23%	22%	15%	17%	19%	32%	19%	15%	16%	14%	17%	17%	16%
% Non-Growth	78%	81%	72%	77%	78%	85%	83%	81%	68%	81%	85%	84%	86%	83%	83%	84%

	Capital Budget Spending															
	Actual											Forecast				
Electric Category	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
T&D Improvements	2,090,600	1,572,700	2,241,100	2,037,800	2,695,600	2,590,000	2,629,900	3,379,100	3,010,300	2,466,000	2,758,700	2,878,068	2,895,380	3,415,493	3,444,473	3,622,165
New Customer Additions	700,300	588,600	691,800	694,600	920,400	1,041,100	856,800	986,600	1,064,300	888,100	1,366,900	957,175	983,925	1,187,145	1,206,173	1,286,522
Outdoor Lighting	391,300	346,900	354,300	353,500	309,300	329,200	389,500	305,200	295,700	309,600	248,700	267,712	281,423	342,710	342,701	359,628
Emergency & Storm Restoration	796,800	910,000	728,900	908,700	900,200	949,700	748,500	2,031,000	1,220,600	2,315,600	(81,700)	1,339,224	1,354,155	1,590,379	1,597,322	1,683,570
Billable work	183,400	193,300	704,300	819,200	611,600	521,300	575,900	480,500	591,200	383,900	637,000	676,909	683,558	809,010	812,547	857,620
Transformers	1,650,300	2,015,700	2,736,700	2,172,300	2,186,400	2,061,800	1,794,100	2,342,000	3,748,400	2,938,700	3,367,900	2,434,392	2,582,342	2,824,038	2,902,620	3,054,949
Meters	326,700	368,900	358,800	567,100	503,200	579,100	864,600	1,062,500	1,401,400	1,462,300	1,622,000	1,466,771	1,547,410	1,763,253	1,787,365	1,852,832
Sub-Totals:	**6,139,400**	**5,996,100**	**7,815,900**	**7,553,200**	**8,126,700**	**8,072,200**	**7,859,300**	**10,586,900**	**11,331,900**	**10,764,200**	**9,919,500**	**10,020,251**	**10,328,193**	**11,932,028**	**12,093,201**	**12,717,286**
Distribution																
Overhead Line Extensions	66,700	190,100	120,900	255,800	39,700	63,600	103,000	78,400	151,600	173,200	140,900	115,015	116,398	148,732	150,558	162,610
Underground Line Extensions	309,400	374,500	482,300	591,100	671,700	765,900	855,400	511,000	780,400	987,500	452,500	966,920	994,010	1,248,444	1,266,319	1,366,936
Street Light Projects	-	28,000	-	4,300	-	3,500	(1,300)	-	-	-	-	4,657	4,737	5,637	5,625	5,929
Telephone Company Requests	69,600	-	-	-	81,800	1,003,100	301,200	668,300	267,200	-	-	13,365	18,985	22,665	22,580	23,788
Highway Projects	(111,600)	828,100	409,700	30,900	170,000	11,500	1,060,000	(519,400)	315,200	23,500	333,600	318,584	297,812	352,591	1,012,579	1,043,251
Distribution Pole Replacements	698,500	599,100	975,400	1,168,500	1,577,900	1,310,000	1,437,500	1,522,200	1,614,000	2,285,500	3,335,000	1,551,171	1,809,384	2,153,189	2,214,972	2,334,567
Specific Projects: Distribution	5,197,200	2,615,100	2,432,700	4,328,400	1,993,500	2,841,100	1,492,200	4,929,900	2,077,200	6,311,800	4,314,900	12,191,099	13,911,248	11,050,740	14,035,294	15,819,016
Sub-Totals:	**6,229,800**	**4,634,900**	**4,421,000**	**6,379,000**	**4,534,600**	**5,998,700**	**5,248,000**	**7,190,400**	**5,205,600**	**9,781,500**	**8,576,900**	**15,160,811**	**17,152,574**	**14,981,998**	**18,707,927**	**20,756,097**
Substation																
Specific Projects: Substation	423,800	1,727,400	578,200	2,044,400	5,177,300	8,774,600	9,615,900	2,748,000	614,000	2,848,300	3,212,700	1,699,762	5,415,393	6,420,793	3,693,529	4,797,465
Sub-Totals:	**423,800**	**1,727,400**	**578,200**	**2,044,400**	**5,177,300**	**8,774,600**	**9,615,900**	**2,748,000**	**614,000**	**2,848,300**	**3,212,700**	**1,699,762**	**5,415,393**	**6,420,793**	**3,693,529**	**4,797,465**
Communications	483,500	3,956,600	(19,200)	(57,600)	1,449,800	360,300	310,000	2,767,800	836,700	1,803,900	1,763,400	3,872,953	4,178,905	3,197,467	3,051,599	2,712,445
Tools, Shop, Garage	127,600	94,900	89,600	81,500	169,900	111,200	117,200	115,100	114,600	188,700	108,700	214,500	194,500	126,700	127,900	127,900
Laboratory	10,100	25,200	14,200	17,700	11,300	55,200	13,400	23,900	11,800	61,500	10,100	14,000	14,000	14,000	14,000	14,000
Office	4,500	7,200	2,000	2,200	5,000	700	4,300	5,000	10,000	25,500	1,300	4,000	7,000	7,000	7,000	7,000
Structures	20,600	98,500	64,600	151,400	55,600	32,900	19,600	312,300	162,500	3,595,200	13,653,200	600,000	236,000	298,000	458,000	333,000
Distribution Totals:	**13,439,300**	**16,540,800**	**12,966,300**	**16,171,800**	**19,530,200**	**23,405,800**	**23,187,700**	**23,749,400**	**18,287,100**	**29,068,800**	**37,245,800**	**31,586,277**	**37,526,565**	**36,977,986**	**38,153,156**	**41,465,193**

13,439,300 16,540,800 12,966,300 16,171,800 19,530,200 23,405,800 23,187,700 23,749,400 18,287,100 29,068,800 37,245,800 31,586,277 37,526,565 36,977,986 38,153,156 41,465,193

5-Year Capital Budget

Budget Category	Actual Spending											5-Year Budget Forecast				
Annual Requirements Blankets: Electric	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
T&D Improvements	2,090,600	1,572,700	2,241,100	2,037,800	2,695,600	2,590,000	$ 2,629,900	$ 3,379,100	$ 3,010,300	$ 2,466,000	$ 2,758,700	$ 2,878,068	$ 2,895,380	$ 3,415,493	$ 3,444,473	$ 3,622,165
New Customer Additions	700,300	588,600	691,800	694,600	920,400	1,041,100	856,800	986,600	1,064,300	888,100	1,366,900	957,175	983,925	1,187,145	1,206,173	1,286,522
Outdoor Lighting	391,300	346,900	354,300	353,500	309,300	329,200	389,500	305,200	295,700	309,600	248,700	267,712	281,423	342,710	342,701	359,628
Emergency & Storm Restoration	796,800	910,000	728,900	908,700	900,200	949,700	748,500	2,031,000	1,220,600	2,315,600	(81,700)	1,339,224	1,354,155	1,590,379	1,597,322	1,683,570
Billable work	183,400	193,300	704,300	819,200	611,600	521,300	575,900	480,500	591,200	383,900	637,000	676,909	683,558	809,010	812,547	857,620
Transformers	1,650,300	2,015,700	2,736,700	2,172,300	2,186,400	2,061,800	1,794,100	2,342,000	3,748,400	2,938,700	3,367,900	2,434,392	2,582,342	2,824,038	2,902,620	3,054,949
Meters	326,700	368,900	358,800	567,100	503,200	579,100	864,600	1,062,500	1,401,400	1,462,300	1,622,000	1,466,771	1,547,410	1,763,253	1,787,365	1,852,832
Sub-Totals:	**$ 6,139,400**	**$ 5,996,100**	**$ 7,815,900**	**$ 7,553,200**	**$ 8,126,700**	**$ 8,072,200**	**$ 7,859,300**	**$10,586,900**	**$11,331,900**	**$10,764,200**	**$ 9,919,500**	**$10,020,251**	**$ 10,328,193**	**$ 11,932,028**	**$ 12,093,201**	**$ 12,717,286**
Distribution: Electric																
Overhead Line Extensions over $20,000	66,700	190,100	120,900	255,800	39,700	63,600	103,000	78,400	151,600	173,200	140,900	115,015	116,398	148,732	150,558	162,610
Underground Line Extensions over $20,000	309,400	374,500	482,300	591,100	671,700	765,900	855,400	511,000	780,400	987,500	452,500	966,920	994,010	1,248,444	1,266,319	1,366,936
Street Light Projects	-	28,000	-	4,300	-	3,500	(1,300)	-	-	-	-	4,657	4,737	5,637	5,625	5,929
Telephone Company Requests	69,600	-	-	-	81,800	1,003,100	301,200	668,300	267,200	-	-	13,365	18,985	22,665	22,580	23,788
Highway Projects	(111,600)	828,100	409,700	30,900	170,000	11,500	1,060,000	(519,400)	315,200	23,500	333,600	318,584	297,812	352,591	1,012,579	1,043,251
Distribution Pole Replacements	698,500	599,100	975,400	1,168,500	1,577,900	1,310,000	1,437,500	1,522,200	1,614,000	2,285,500	3,335,000	1,551,171	1,809,384	2,153,189	2,214,972	2,334,567
Specific Projects: Distribution	5,197,200	2,615,100	2,432,700	4,328,400	1,993,500	2,841,100	1,492,200	4,929,900	2,077,200	6,311,800	4,314,900	12,191,099	13,911,248	11,050,740	14,035,294	15,819,016
Sub-Totals:	**$ 6,229,800**	**$ 4,634,900**	**$ 4,421,000**	**$ 6,379,000**	**$ 4,534,600**	**$ 5,998,700**	**$ 5,248,000**	**$ 7,190,400**	**$ 5,205,600**	**$ 9,781,500**	**$ 8,576,900**	**$15,160,811**	**$ 17,152,574**	**$ 14,981,998**	**$ 18,707,927**	**$ 20,756,097**
Substation:Electric																
Specific Projects: Substation	423,800	1,727,400	578,200	2,044,400	5,177,300	8,774,600	9,615,900	2,748,000	614,000	2,848,300	3,212,700	1,699,762	5,415,393	6,420,793	3,693,529	4,797,465
Sub-Totals:	**$ 423,800**	**$ 1,727,400**	**$ 578,200**	**$ 2,044,400**	**$ 5,177,300**	**$ 8,774,600**	**$ 9,615,900**	**$ 2,748,000**	**$ 614,000**	**$ 2,848,300**	**$ 3,212,700**	**$ 1,699,762**	**$ 5,415,393**	**$ 6,420,793**	**$ 3,693,529**	**$ 4,797,465**
Communications	**483,500**	**3,956,600**	**(19,200)**	**(57,600)**	**1,449,800**	**360,300**	**$ 310,000**	**$ 2,767,800**	**$ 836,700**	**$ 1,803,900**	**$ 1,763,400**	**$ 3,872,953**	**$ 4,178,905**	**$ 3,197,467**	**$ 3,051,599**	**$ 2,712,445**
Tools, Shop, Garage	**127,600**	**94,900**	**89,600**	**81,500**	**169,900**	**111,200**	**$ 117,200**	**$ 115,100**	**$ 114,600**	**$ 188,700**	**$ 108,700**	**$ 214,500**	**$ 194,500**	**$ 126,700**	**$ 127,900**	**$ 127,900**
Laboratory	**10,100**	**25,200**	**14,200**	**17,700**	**11,300**	**55,200**	**$ 13,400**	**$ 23,900**	**$ 11,800**	**$ 61,500**	**$ 10,100**	**$ 14,000**	**$ 14,000**	**$ 14,000**	**$ 14,000**	**$ 14,000**
Office	**4,500**	**7,200**	**2,000**	**2,200**	**5,000**	**700**	**$ 4,300**	**$ 5,000**	**$ 10,000**	**$ 25,500**	**$ 1,300**	**$ 4,000**	**$ 7,000**	**$ 7,000**	**$ 7,000**	**$ 7,000**
Structures	**20,600**	**98,500**	**64,600**	**151,400**	**55,600**	**32,900**	**$ 19,600**	**$ 312,300**	**$ 162,500**	**$ 3,595,200**	**$13,653,200**	**$ 600,000**	**$ 236,000**	**$ 298,000**	**$ 458,000**	**$ 333,000**
Distribution Totals:	**$13,439,300**	**$16,540,800**	**$12,966,300**	**$16,171,800**	**$19,530,200**	**$23,405,800**	**$23,187,700**	**$23,749,400**	**$18,287,100**	**$29,068,800**	**$37,245,800**	**$31,586,277**	**$ 37,526,565**	**$ 36,977,986**	**$ 38,153,156**	**$ 41,465,193**

5 Year Budget Starting 2021 •
Unitil Service Corp

Priority •	Status	Code	Item	2021	2022	2023	2024	2025	Sub-Total	Catgory	Division	UES Allocations 2021	2022	2023	2024	2025
3 •	[A] Accepted	GSC01	Replace and Upgrade Gas SCADA Master	0	0	0	0	0	0	S	Gas	-	-	-	-	-
3 •	[A] Accepted	GSC02	2021 General Software Enhancements	75,000	0	0	0	0	75,000	S	All	24,000	-	-	-	-
2 •	[A] Accepted	GSC04	Reporting Blanket	100,000	0	0	0	0	100,000	S	All	32,000	-	-	-	-
2 •	[A] Accepted	GSC05	2021 Regulatory Work Blanket	22,000	0	0	0	0	22,000	S	All	7,040	-	-	-	-
1 •	[A] Accepted	GSC06	2021 Customer Facing Enhancements	1,067,465	0	0	0	0	1,067,465	S	All	341,589	-	-	-	-
1 •	[A] Accepted	GSC08	Metersense Upgrade 2021	18,800	0	0	0	0	18,800	S	All	6,016	-	-	-	-
1 •	[A] Accepted	GSC09	AMI Command Center Upgrade to 8.0	35,000	0	0	0	0	35,000	S	All	11,200	-	-	-	-
2 •	[A] Accepted	GSC10	Close - Workflow & Electronic Review	50,000	0	0	0	0	50,000	S	All	16,000	-	-	-	-
1 •	[A] Accepted	GSC11	FERC to XBRL	138,000	0	0	0	0	138,000	S	All	44,160	-	-	-	-
3 •	[A] Accepted	GSC14	Virtual Payables - Credit Card	3,000	0	0	0	0	3,000	S	All	960	-	-	-	-
2 •	[A] Accepted	GSC15	Web Ops Modernization	200,000	0	0	0	0	200,000	S	All	64,000	-	-	-	-
2 •	[A] Accepted	GSC16	Advanced Distribution Management System (ADMS) - Grid Mod	1,030,000	0	0	0	0	1,030,000	G	Electric	710,700	-	-	-	-
2 •	[A] Accepted	GSC17	Unitil website upgrade - Year 2 of 2	170,000	0	0	0	0	170,000	S	All	54,400	-	-	-	-
2 •	[A] Accepted	GSC19	Modernize GTRAC & CSI	72,000	0	0	0	0	72,000	S	All	23,040	-	-	-	-
2 •	[A] Accepted	GSC21	Customer Experience Mgmt Project - Year 2 of 3	2,665,000	0	0	0	0	2,665,000	S	All	852,800	-	-	-	-
1 •	[A] Accepted	GSC22	Customer exports used for Gas Engineering CMM Module	20,400	0	0	0	0	20,400	S	Gas	-	-	-	-	-
2 •	[A] Accepted	GSC25	GTI / Pxio VR Training Project	135,000	0	0	0	0	135,000	S	Gas	-	-	-	-	-
1 •	[A] Accepted	GSC26	Command Center Upgrade to Cellular	68,000	0	0	0	0	68,000	S	All	21,760	-	-	-	-
1 •	[A] Accepted	GSC27	TOU Testing	375,950	0	0	0	0	375,950	S	Electric	259,406	-	-	-	-
2 •	[A] Accepted	GSC28	Cloud Data Warehouse, Carryover	50,000	0	0	0	0	50,000	S	All	16,000	-	-	-	-
2 •	[A] Accepted	GSC29	DevOps Implementation Project, Carryover	150,000	0	0	0	0	150,000	S	All	48,000	-	-	-	-
2 •	[A] Accepted	GSC30	Damage Assessment Mobile Platform - Grid Mod, Carry Over	125,000	0	0	0	0	125,000	G	Electric	86,250	-	-	-	-
2 •	[A] Accepted	GSC31	Ubisense Custom Enhancements, Carryover	155,059	0	0	0	0	155,059	S	Gas	-	-	-	-	-
1 •	[A] Accepted	GSC32	USC Time & Billing Upgrade/Replacement, Carryover	50,000	0	0	0	0	50,000	S	All	16,000	-	-	-	-
3 •	[A] Accepted	GSC33	ADP Modules - Data Cloud, Time Off and Time Entry, Carryover	141,000	0	0	0	0	141,000	S	All	45,120	-	-	-	-
2 •	[A] Accepted	GSC35	Ring Central Phase II	76,600	0	0	0	0	76,600	S	All	24,512	-	-	-	-
2 •	[A] Accepted	GSC36	Data Sharing: Unitil Core Platform Design	600,000	0	0	0	0	600,000	G	Electric	414,000	-	-	-	-
2 •	[A] Accepted	GSC37	S&S Oracle Upgrade Test Environment	200,000	0	0	0	0	200,000	S	All	64,000	-	-	-	-
2 •	[A] Accepted	GSC38	Data Sharing: Community Aggregation Module	200,000	0	0	0	0	200,000	G	Electric	138,000	-	-	-	-
2 •	[A] Accepted	GSC39	Grid Mod: AMI/OMS Phase 2 Collector Integration	100,000	0	0	0	0	100,000	G	Electric	69,000	-	-	-	-
2 •	[A] Accepted	GSC01	GIS Upgrade to Utility Network	0	395,000	0	0	0	395,000	S	All	-	126,400	-	-	-
3 •	[A] Accepted	GSC02	2022 General Software Enhancements	0	217,799	0	0	0	217,799	S	All	-	69,696	-	-	-
2 •	[A] Accepted	GSC03	CMS Enhancements - Yr 4 CMS Reporting	0	50,000	0	0	0	50,000	S	All	-	16,000	-	-	-
2 •	[A] Accepted	GSC05	Reporting Blanket	0	60,000	0	0	0	60,000	S	All	-	19,200	-	-	-
2 •	[A] Accepted	GSC06	Regulatory Work Blanket	0	100,000	0	0	0	100,000	S	All	-	32,000	-	-	-
1 •	[A] Accepted	GSC07	2022 Customer Facing Enhancements	0	500,000	0	0	0	500,000	S	All	-	160,000	-	-	-
1 •	[A] Accepted	GSC10	MV-90xi Upgrade V6.0 to X.X 2022	0	90,000	0	0	0	90,000	S	Electric	-	62,100	-	-	-
2 •	[A] Accepted	GSC12	Cloud Discovery and Migration Work	0	500,000	0	0	0	500,000	S	All	-	160,000	-	-	-
3 •	[A] Accepted	GSC12	Create new Electric Estimating Model	0	59,500	0	0	0	59,500	S	Electric	-	41,055	-	-	-
2 •	[A] Accepted	GSC13	Cognos Upgrade to V11 Analytics	0	72,220	0	0	0	72,220	S	All	-	23,110	-	-	-
2 •	[A] Accepted	GSC13	Web Ops Modernization	0	200,000	0	0	0	200,000	S	All	-	64,000	-	-	-
2 •	[A] Accepted	GSC13	TOU and Advanced Rate Design Implementation	0	500,000	0	0	0	500,000	S	Electric	-	345,000	-	-	-
2 •	[A] Accepted	GSC14	Customer Experience Mgmt Project Year 3 of 3	0	########	0	0	0	1,940,000	S	All	-	620,800	-	-	-
2 •	[A] Accepted	GSC15	Distributed Energy Resource Management System (DERMS) - Grid Mod	0	475,000	0	0	0	475,000	G	Electric	-	327,750	-	-	-
1 •	[A] Accepted	GSC16	AMI Command Center Upgrade - 2022	0	92,000	0	0	0	92,000	S	All	-	29,440	-	-	-
2 •	[A] Accepted	GSC17	Advanced Distribution Management System (ADMS) - Grid Mod	0	640,000	0	0	0	640,000	G	Electric	-	441,600	-	-	-
2 •	[A] Accepted	GSC18	Flexi Upgrade	0	75,000	0	0	0	75,000	S	All	-	24,000	-	-	-
2 •	[A] Accepted	GSC18	Utility Bill Redesign	0	171,575	0	0	0	171,575	S	All	-	54,904	-	-	-
2 •	[A] Accepted	GSC19	Smart Speaker Integration	0	150,000	0	0	0	150,000	S	All	-	48,000	-	-	-
1 •	[A] Accepted	GSC20	Metersense Upgrade 2022	0	50,000	0	0	0	50,000	S	All	-	16,000	-	-	-
2 •	[A] Accepted	GSC21	Payment Alternatives	0	150,000	0	0	0	150,000	S	All	-	48,000	-	-	-
2 •	[A] Accepted	GSC24	Construction QA Manager System	0	205,000	0	0	0	205,000	S	Gas	-	-	-	-	-
2 •	[A] Accepted	GSC36	Gas EDI/Complete Billing	0	0	0	0	0	0	S	Gas	-	-	-	-	-
2 •	[A] Accepted	GSC44	Flexi Migration to Cloud	0	50,000	0	0	0	50,000	S	All	-	16,000	-	-	-
3 •	[A] Accepted	GSC47	Capital Budget System	0	450,000	0	0	0	450,000	S	All	-	144,000	-	-	-
2 •	[A] Accepted	GSC48	Data Sharing: Behind the Meter Module	0	105,000	0	0	0	105,000	G	Electric	-	72,450	-	-	-
2 •	[A] Accepted	GSC01	Distributed Energy Resource Management System (DERMS) - Grid Mod	0	0	275,000	0	0	275,000	G	Electric	-	-	189,750	-	-
3 •	[A] Accepted	GSC01	Power Plan Upgrade	0	0	295,000	0	0	295,000	S	All	-	-	94,400	-	-
3 •	[A] Accepted	GSC02	2023 General Software Enhancements	0	0	250,469	0	0	250,469	S	All	-	-	80,150	-	-
2 •	[A] Accepted	GSC02	Work Order Job Scheduler	0	0	350,000	0	0	350,000	S	All	-	-	112,000	-	-
2 •	[A] Accepted	GSC03	CMS Enhancements - Yr 5 Inspection Rewrite	0	0	100,000	0	0	100,000	S	Gas	-	-	-	-	-

5 Year Budget Starting 2021 •																	
Unitil Service Corp															**UES Allocations**		
Priority •	Status	Code	Item	2021	2022	2023	2024	2025	Sub-Total	Catgory	Division	2021	2022	2023	2024	2025
2 •	[A] Accepted	GSC04	Reporting Blanket	0	0	48,750	0	0	48,750	S	All	-	-	15,600	-	-
2 •	[A] Accepted	GSC05	Regulatory Work Blanket	0	0	100,000	0	0	100,000	S	All	-	-	32,000	-	-
1 •	[A] Accepted	GSC06	2023 Customer Facing Enhancements	0	0	########	0	0	1,012,958	S	All	-	-	324,147	-	-
1 •	[A] Accepted	GSC07	Metersense Upgrade 2023	0	0	50,000	0	0	50,000	S	All	-	-	16,000	-	-
1 •	[A] Accepted	GSC08	AMI Command Center Upgrade - 2023	0	0	92,000	0	0	92,000	S	All	-	-	29,440	-	-
2 •	[A] Accepted	GSC10	Personalized selling / next best action	0	0	500,000	0	0	500,000	s	All	-	-	160,000	-	-
2 •	[A] Accepted	GSC11	Cloud Discovery and Migration Work	0	0	600,000	0	0	600,000	S	All	-	-	192,000	-	-
2 •	[A] Accepted	GSC12	Web Ops Modernization	0	0	200,000	0	0	200,000	S	All	-	-	64,000	-	-
2 •	[A] Accepted	GSC15	DevOps Implementation Project	0	0	232,500	0	0	232,500	S	All	-	-	74,400	-	-
2 •	[A] Accepted	GSC16	Customer Experience System Phase 2	0	0	600,000	0	0	600,000	S	All	-	-	192,000	-	-
2 •	[A] Accepted	GSC17	Advanced Distribution Management System (ADMS) - Grid Mod	0	0	275,000	0	0	275,000	G	Electric	-	-	189,750	-	-
3 •	[A] Accepted	GSC20	Capital Budget System	0	0	470,000	0	0	470,000	S	All	-	-	150,400	-	-
2 •	[A] Accepted	GSC21	Data Sharing: System Data Module	0	0	75,000	0	0	75,000	G	Electric	-	-	51,750	-	-
2 •	[A] Accepted	GSC01	Flexi Upgrade	0	0	0	75,000	0	75,000	S	All	-	-	-	24,000	-
1 •	[A] Accepted	GSC03	Metersense Upgrade 2024	0	0	0	50,000	0	50,000	S	All	-	-	-	16,000	-
1 •	[A] Accepted	GSC04	AMI Command Center Upgrade - 2024	0	0	0	92,000	0	92,000	S	All	-	-	-	29,440	-
3 •	[A] Accepted	GSC05	2024 General Software Enhancements	0	0	0	350,000	0	350,000	S	All	-	-	-	112,000	-
2 •	[A] Accepted	GSC06	Reporting Blanket	0	0	0	48,750	0	48,750	S	All	-	-	-	15,600	-
2 •	[A] Accepted	GSC08	Web Ops Modernization	0	0	0	500,000	0	500,000	S	All	-	-	-	160,000	-
2 •	[A] Accepted	GSC09	Cloud Discovery and Migration Work	0	0	0	500,000	0	500,000	S	All	-	-	-	160,000	-
2 •	[A] Accepted	GSC10	DevOps Implementation Project	0	0	0	482,500	0	482,500	S	All	-	-	-	154,400	-
1 •	[A] Accepted	GSC12	Artificial Intelligence Enterprise Solution	0	0	0	150,000	0	150,000	G	All	-	-	-	48,000	-
2 •	[A] Accepted	GSC14	Customer Engagement Vision Items	0	0	0	200,000	0	200,000	S	All	-	-	-	64,000	-
2 •	[A] Accepted	GSC16	Advanced Distribution Management System (ADMS) - Grid Mod	0	0	0	175,000	0	175,000	G	Electric	-	-	-	120,750	-
2 •	[A] Accepted	GSC23	AOC Click to Report System	0	0	0	180,000	0	180,000	S	All	-	-	-	57,600	-
1 •	[A] Accepted	GSC45	FCS Upgrade	0	0	0	15,000	0	15,000	S	All	-	-	-	4,800	-
2 •	[A] Accepted	GSC46	Locusview Mobile / CMS Integration	0	0	0	30,000	0	30,000	S	Gas	-	-	-	-	-
1 •	[A] Accepted	GSC47	enQuesta Ver. 6.0 Upgrade	0	0	0	########	0	3,281,279	S	All	-	-	-	1,050,009	-
2 •	[A] Accepted	GSC48	Regulatory Work Blanket	0	0	0	100,000	0	100,000	S	All	-	-	-	32,000	-
1 •	[A] Accepted	GSC02	Metersense Upgrade 2025	0	0	0	0	50,000	50,000	S	All	-	-	-	-	16,000
1 •	[A] Accepted	GSC03	AMI Command Center Upgrade - 2025	0	0	0	0	92,000	92,000	S	All	-	-	-	-	29,440
2 •	[A] Accepted	GSC07	Regulatory Work Blanket	0	0	0	0	100,000	100,000	S	All	-	-	-	-	32,000
1 •	[A] Accepted	GSC22	enQuesta Ver. 6.0 Upgrade	0	0	0	0	########	1,640,641	S	All	-	-	-	-	525,005
3 •	[A] Accepted	GSC23	2025 General Software Enhancements	0	0	0	0	350,000	350,000	S	All	-	-	-	-	112,000
2 •	[A] Accepted	GSC24	Reporting Blanket	0	0	0	0	48,750	48,750	S	All	-	-	-	-	15,600
2 •	[A] Accepted	GSC25	Web Ops Modernization	0	0	0	0	500,000	500,000	S	All	-	-	-	-	160,000
2 •	[A] Accepted	GSC26	Cloud Discovery and Migration Work	0	0	0	0	500,000	500,000	S	All	-	-	-	-	160,000
2 •	[A] Accepted	GSC27	DevOps Implementation Project	0	0	0	0	482,500	482,500	S	All	-	-	-	-	154,400
3 •	[A] Accepted	GSC28	Blanket Data Project	0	0	0	0	########	1,000,000	S	All	-	-	-	-	320,000
2 •	[A] Accepted	GSC29	Customer Engagement Marketplace	0	0	0	0	250,000	250,000	S	All	-	-	-	-	80,000
2 •	[A] Accepted	GSC30	Grid Mod Improvements	0	0	0	0	500,000	500,000	G	Electric	-	-	-	-	345,000
Sub-Totals:				8,093,274	########	########	########	########				3,389,952	2,961,505	1,967,787	2,048,599	1,949,445
1 •	[A] Accepted	GPC01	2021 Cyber Security Enhancements	45,000	0	0	0	0	45,000	N	All	14,400	-	-	-	-
2 •	[A] Accepted	GPC02	2021 Infrastructure PC and Network	855,252	0	0	0	0	855,252	N	All	273,681	-	-	-	-
2 •	[A] Accepted	GPC04	Gas SCADA Communications Upgrade	0	0	0	0	0	0	N	Gas	-	-	-	-	-
2 •	[A] Accepted	GPC05	Windows Server Upgrades	6,000	0	0	0	0	6,000	N	All	1,920	-	-	-	-
1 •	[A] Accepted	GPC01	2022 Cyber Security Enhancements	0	100,000	0	0	0	100,000	N	All	-	32,000	-	-	-
2 •	[A] Accepted	GPC02	2022 Infrastructure PC and Network	0	########	0	0	0	1,322,500	N	All	-	423,200	-	-	-
3 •	[A] Accepted	GPC03	Network Segmentation	0	160,000	0	0	0	160,000	N	All	-	51,200	-	-	-
1 •	[A] Accepted	GPC01	2023 Cyber Security Enhancements	0	0	100,000	0	0	100,000	N	All	-	-	32,000	-	-
2 •	[A] Accepted	GPC02	2023 Infrastructure PC and Network	0	0	########	0	0	1,520,875	N	All	-	-	486,680	-	-
2 •	[A] Accepted	GPC01	2024 Infrastructure PC and Network	0	0	0	########	0	1,750,000	N	All	-	-	-	560,000	-
1 •	[A] Accepted	GPC02	2024 Cyber Security Enhancements	0	0	0	100,000	0	100,000	N	All	-	-	-	32,000	-
3 •	[A] Accepted	GPC01	2025 Cyber Security Enhancements	0	0	0	0	100,000	100,000	N	All	-	-	-	-	32,000
2 •	[A] Accepted	GPC02	2025 Infrastructure PC and Network	0	0	0	0	########	1,000,000	N	All	-	-	-	-	320,000
Sub-Totals:				906,252	########	########	########	########	7,059,627			290,001	506,400	518,680	592,000	352,000
Totals:				8,999,526	########	########	########	########	#########			**3,679,953**	**3,467,905**	**2,486,467**	**2,640,599**	**2,301,445**

Category	2021	2022	2023	2024	2025
Software/Systems Upgrades (S)	6,038,274	6,078,094	4,901,677	5,904,529	5,013,891
Computer, Network, & Office Equipment (N)	906,252	1,582,500	1,620,875	1,850,000	1,100,000
Grid Mod (G)	2,055,000	1,220,000	625,000	325,000	500,000
Total	8,999,526	8,880,594	7,147,552	8,079,529	6,613,891
Building Improvements & Furniture	467,002	1,172,503	569,503	357,505	362,904
USC/URC Total	9,466,528	10,053,097	7,717,055	8,437,034	6,976,795

This comes from Accounting -- "Master Allocation Guidelines - Special Purpose Allocators"
Each colored section has been linked to the tab where the file has been copied to.

2020

Linked to "Special Purpose Allocators" Tab

ALL COMPANIES WITH GRANITE		ALL COMPANIES SPLIT BY DIVISION	
UES	31%	UES	31%
FGE	25%	FGE-E	14%
NU-NH	19%	FGE-G	11%
NU-ME	23%	NU-NH	19%
GRANITE	2%	NU-ME	23%
		GRANITE	2%
	100%		100%

Linked to "Special Purpose Allocators" Tab

GAS ONLY WITH GST		GAS ONLY NO GST		JUST ELECTRIC	
FGE	20%	FGE	21%	UES	69%
NU-NH	32%	NU-NH	34%	FGE	31%
NU-ME	43%	NU-ME	45%		100%
GRANITE	5%		100%		
	100%				

ALL COMPANIES WITHOUT GRANITE		FGE & UES Only	
UES	32%	FGE	55.36%
FGE	25%	UES	44.64%
NU-NH	19%		100.00%
NU-ME	24%		
	100%		

[THIS PAGE INTENTIONALLY LEFT BLANK]

Unitil Energy Systems, Inc.

Grid Modernization Plan

March 2021

THIS PAGE INTENTIONALLY LEFT BLANK

TABLE OF CONTENTS

Contents

LIST OF TABLES

LIST OF FIGURES

LIST OF ACRONYMS

ADMS	Advanced Distribution Management System
ADRP	Active Demand Response Program
AMF	Advanced Metering Functionality
AMI	Automated Metering Infrastructure
AO	Application Owner
API	Application Programming Interface
BCA	Benefit Cost Analysis
BIA	Business Impact Analysis
C&I	Commercial & industrial
CEM	Customer Engagement Management
CHP	Combined Heat and Power
CIA	Confidentiality, Integrity, and Availability
CIP	Critical Infrastructure Protection
CIS	Customer Information System
CISO	Chief Information Security Officer
CKAIDI	Circuit SAIDI
CKAIFI	Circuit SAIFI
CMS	Compliancy Management System
CO_2	Carbon Dioxide
COE	Company Owned Equipment
CPP	Critical Peak Pricing
CSV	Comma-Separated Values
DA	Distribution Automation
DC	Direct Current
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DIMP	Distribution Integrity Management Program
DMV	Department of Motor Vehicles
EE	Energy Efficiency
EEI	Edison Electric Institute
E-ISAC	Electricity Information Sharing and Analysis Center
ESPI	Energy Service Provider Interface
ETL	Extract, Transform, Load
EV	Electric Vehicle
FAN	Field Area Network
FLISR	Fault location, isolation, and service restoration
FOCI	Foreign-Owned, Controlled, or Influenced
GBC	Green Button Connect
GHG	Greenhouse Gas
GIS	Geographic Information System
GMP	Grid Modernization Plan

GWhr	Gigawatt Hours
ICS-CERT	Industrial Control Systems Cyber Emergency Response Team
ISA	Interconnection Service Agreement
ISO-NE	Independent System Operator – New England
IT	Information Technology
KW	Kilowatt
KWh	Kilowatt-hours
LCIRP	Least Cost Integrated Resource Plan
LTC	Load Tap Changer
M&V	Measurement and Verification
MA	Massachusetts
MIMS	Mobile Information Management System
MDMS	Meter Data Management System
MW	Megawatt
MWh	Megawatt-hours
NAESB	North American Energy Standards Board
NERC	North American Electric Reliability Corporation
NH	New Hampshire
NIST	National Institute of Standards and Technology
NISTIR	National Institute of Standards and Technology Interagency or Internal Reports
NWA	Non-Wires Alternative
OMS	Outage Management System
OT	Operations Technology
PCI	Payment Card Industry
PII	Personally Identifiable Information
PLC	Power Line Carrier
PUC	Public Utilities Commission
PV	Photovoltaics
REST	Representational State Transfer
RFP	Request for Proposal
RSA	Revised Statutes Annotated
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SB	Senate Bill
SCADA	Supervisory Control and Data Acquisition
T&D	Transmission and Distribution
TIMP	Transmission Integrity Management Program
TOU	Time-of-Use
TVR	Time varying rates
UES	Unitil Energy Systems, Inc.
VAr	Volt-Ampere Reactive
VVO	Volt/VAr Optimization
WISP	Written Information Security Plan

XML	eXtensible Markup Language

1 EXECUTIVE SUMMARY

Grid Modernization investments cover “foundational” and “geographical” investments. “Foundational” grid modernization projects are designed to facilitate implementation of base functionality required to advance the grid. “Geographic” grid modernization investments target specific locational constraints on the distribution system to alleviate capacity concerns by introducing more distributed energy resources in a specific geographic area.

This plan represents “foundational” grid modernization investments. This plan describes Unitil Energy Systems, Inc.’s (“UES” or the “Company”) vision of the advanced grid as an enabling platform that allows and encourages new and different use cases. These use cases cannot be supported without specific technology building blocks that will provide the ability for increased grid intelligence and data sharing.

This plan presents a series of eight objectives that together ensure support of a modern energy ecosystem. Our objectives are crafted with guidance from the United States Department of Energy, Massachusetts Department of Public Utilities, and New Hampshire Public Utilities Commission, and are used to identify the investments and technologies that best serve this new era. The eight key objective and areas of interest are: 1) Environmentally Friendly; 2) Safety and Reliability; 3) Customer Service; 4) Security; 5) Flexibility; 6) Affordability; 7) Demand and Asset Optimization; and 8) Technology Innovation. Balancing all eight objectives is the key to unlocking an electric utility’s future state.

This plan provides a roadmap to the future, and identifies six categories of technologies required to develop the grid as an enabling platform: 1) Grid Intelligence; 2) Advanced Metering; 3) Distributed Energy Resources; 4) Advanced System Planning and Forecasting; 5) Enhanced Customer Services; and 6) Innovative Rate Design. The plan maps projects and functionalities to the categories and objects to provide transparency.

The plan continues on to detail specific foundational grid modernization projects required to facilitate the distribution system as an enabling platform. The plan includes a description of the project and provides the project costs, benefits and a timeline for implementation. The projects are presented as a portfolio of projects with a combined benefit cost ratio. A portfolio approach has been used because some projects cannot be accomplished without support from other projects. For instance, Volt/VAr Optimization (VVO) provides an opportunity for demand and energy savings directly to the customer. However, a VVO system cannot be successful without a Field Area Network (FAN) that provides the means to communicate between field devices and the central office. The FAN by itself does not provide any direct benefits, but it is a foundational investment required for VVO.

	Project Costs (000's)										
Projects	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Field Area Network	$ 90	$ 56	$ 127	$ 626	$ 325	$ 463	$ 780	$ 811	$ 640	$ 704	$ 4,622
ADMS and DERMS	$ 668	$ 468	$ 378	$ 298	$ 170	$ -	$ -	$ -	$ -	$ -	$ 1,981
Volt/VAR Optimization	$ -	$ 383	$ 2,000	$ 2,929	$ 2,731	$ 2,862	$ 2,880	$ 3,416	$ 3,488	$ 4,292	$ 24,981
SCADA	$ -	$ 1,530	$ 1,740	$ 760	$ 790	$ 250	$ 340	$ 420	$ 550	$ 760	$ 7,140
Mobile Damage Assessment	$ 449	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 449
AMI/OMS Integration	$ 107	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 107
Data Sharing Platform	$ 449	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 449
Total	$1,763	$2,437	$4,245	$4,612	$4,016	$3,575	$4,000	$4,647	$4,678	$5,756	$ 39,729

Table 1: Grid Modernization Spending Plan

The Company examined the benefits that each project could provide. Some projects were relatively easy to estimate, including those that yield operational or direct customer cost savings. Other project benefits, like those that might improve the satisfaction of customers, are harder to quantify. Benefits that improve the operation of the grid and reduce costs overall are designated as “grid” benefits while those that lower the costs for customers on their bill (reduced energy consumption or capacity), or reduce the effects of outages are designated as customer benefits. The projects presented in this plan provide customers with net benefits using a 15 or 20 year net present value analysis.

	20 Year NPV				15 Year NPV			
Projects	NPV Benefits (000's)	NPV Capital Costs (000's)	NPV O&M Costs (000's)	B/C Ratio	NPV Benefits (000's)	NPV Capital Costs (000's)	NPV O&M Costs (000's)	B/C Ratio
Field Area Network	$0	$2,541	$586	-	$0	$2,541	$430	-
ADMS and DERMS	$0	$1,855	$543	-	$0	$1,855	$451	-
Volt/VAR Optimization	$21,841	$14,985	$0	1.46	$16,500	$14,985	$0	1.10
SCADA	$9,040	$4,816	$0	1.88	$6,806	$4,816	$0	1.41
Mobile Damage Assessment	$8,412	$385	$281	12.63	$7,221	$385	$237	11.61
AMI/OMS Integration	$1,445	$92	$64	9.26	$1,241	$92	$54	8.50
Data Sharing Platform	$0	$385	$329	-	$0	$385	$278	-
Totals	$ 40,739	$ 25,059	$ 1,804	1.52	$31,768	$25,059	$1,450	1.20

Table 2: Benefit Cost Analysis

Metrics provide the opportunity for our customers, stakeholders and the Commission to measure the plan’s progress towards grid modernization. The purpose of these metrics is to determine how performance can be changed because of grid modernization activities. Weather, customer behavior, economic conditions and other factors will have a significant influence on the parameters being measured under these metrics. As the Company begins to implement its grid modernization plan, the changes resulting from grid modernization may be subtle and difficult to detect. The use of baselines against which to measure ongoing performance will help develop an understanding of how the Company’s grid modernization efforts are “moving the needle” in terms of progressing towards the achievement of the Commission’s Grid Modernization objectives.

The plan describes how cyber security, privacy and data access challenges will be addressed. The plan details an approach to stakeholder involvement and annual reporting requirements designed to update and refocus the plan on an annual basis to meet the need of our stakeholders.

This plan is a starting point. It defines some critical foundational grid modernization investments that are required to develop the grid into an enabling platform. The plan is the start of a long journey towards an advanced grid that provides customers with the ability to maximize the benefits of their investments. Least Cost Integrated Resource Planning is designed to identify the geographical investments focused on alleviating locational constraints of the system. However, these foundational investments are required to maximize the value of the geographical investments.

2 ADVANCING THE GRID VISION

Electricity is the lifeblood of modern civilization. It powers homes, businesses, industrial production and even cars. It powers the basic necessities of heat, light, refrigeration and cooking, as well as computers, networks, communication services and entertainment. It keeps us connected. It is essential to our growth, prosperity, standard of living and sense of well-being. Without it, modern society grinds to a halt. Everything runs on electricity. And yet, every kWh of electricity we consume contributes almost a pound of carbon dioxide to the atmosphere.

The global need to reduce carbon emissions has driven an unprecedented transformation of the energy sector. Enormous investments in clean energy and efficient end-use technologies have led to sharp declines in greenhouse gas emissions. Technology innovation has both accelerated and reinforced this transformation as customers now have access to services, markets and home energy technologies previously unimagined. Advancements in technology are driving down the cost of clean energy, making it more affordable for consumers. Energy markets continue to develop as innovators develop new tools to control and manage energy usage and market new energy services directly to end-use customers.

As customers adopt new technologies, and as distributed energy resources are increasingly connected to the distribution system, the fundamental architecture of the electricity delivery system (the “grid”) must change. The 20th Century electric grid, originally designed to distribute power from large centralized generating plants, must now integrate a wide array of distributed load, storage and generation resources. A grid that was designed for “one way” power flow must now accommodate two-way power flow, increasing the need for sophisticated protection, communication, metering, and intelligence. The grid must also provide opportunities for customers to understand and actively participate in energy markets to enhance efficient utilization and consumption of electricity, while delivering improved reliability and power quality.

Utility operations are transitioning away from the traditional model of energy delivery, to one that integrates and optimizes the needs and interests of consumers, producers, markets, service providers and other participants. New markets and new technologies are rapidly emerging in response to changing policies, climate action, and the changing preferences of customers. We are seeing a significant transformation in how customers are powering their homes and businesses, including the ability to generate and store their own electricity. More recently, the promise of affordable electric vehicles has moved from niche to mainstream. Implementing enabling technologies and programs to facilitate these activities will make the electric system more efficient, economic and environmentally friendly.

For over a decade, the Company has visualized the utility of the future as an enabling platform with the capabilities to unlock the full potential of today’s customers, markets and technologies. Our Vision is to transform the way people meet their evolving energy needs to create a clean and sustainable future. We are at a tipping point where the time to achieve this vision is now.

2.1 Enabling Platform for the 21st Century

A reliable, affordable and fully modernized electric grid is an essential pillar of modern society. It will power the basic necessities of life while supporting new technologies, services and interactivity. It will operate more efficiently, optimize grid-connected resources and enable dramatic expansion of clean energy to protect and preserve the environment. It will foster innovation and enable new markets by optimizing benefits to customers, service providers and other stakeholders. At its fullest potential, it will harness technology innovation to connect customers, markets, solution providers and new technologies to achieve the full potential of an advanced 21st Century energy system.

Over the years this vision has been variously referred to as Grid Modernization, or the Modern Grid, and even the Smart Grid. But what is a Modernized Grid exactly? What does a Smart Grid look like? Is it the poles, wires and electrical infrastructure of the utility? Is it an intelligent, highly digitized electricity network that forms the basis for a "smart" power delivery system? Does it refer to the utility system, or the broader integration of customers, markets, solution providers, and others? If you ask ten different people, you will get ten different answers.

To achieve the promise of a fully modernized grid, the Company views the electric grid and the devices connected to it as a communicating, intelligent grid-connected ecosystem of people, devices, information and services. The grid is only a part of this larger energy ecosystem, but it is the foundation upon which everything is built. The role of utility in this context is to enable seamless grid access, link participants, optimize resources and foster technology innovation. The modern grid isn't just an electrical network, it's a community of grid-connected and grid-enabled customers and third parties.

To provide a simple analogy, one could ask – what is the internet? In strictly technical terms the internet is a global system of interconnected computer networks that use a standard Internet protocol suite (TCP/IP) to link billions of devices worldwide. But ask any non-technical person what the internet is, and they will describe a vast world of services and information where they can access online shopping, banking, news, social media and entertainment services. It's where people go to trade stocks, make dinner reservations, download books, and connect with other people. The internet is the primary source of information, entertainment content and interactive services for most people in the 21st Century.

From a user perspective, the internet isn't communication infrastructure and it isn't the network of their Internet Service Provider. Instead, the internet is defined by its content, services, connectivity and interactivity. It connects billions of people and devices to an unlimited universe of services and information, and is a platform for endless innovation. The Internet of Things has quickly transitioned to the Internet of Everything.

The modern grid can be thought of in similar terms. The utility grid is clearly the foundation upon which a more advanced energy ecosystem will be built. But from a user perspective, the critical ingredient to achieve the promise of a "Smart Grid" is not electricity, but information. The grid of the future will provide seamless two-way flows of both energy and information. It will be defined not by the electricity it carries, but by the information, functionality and interactive services it provides. In fact, this vision is a part of what has become known as Internet of Energy (IoE).

2.2 Merging Power and Information

The advanced grid will be much more than a "poles and wires" delivery system for electricity. It will enable electrical, informational and financial transactions among customers, grid operators, service providers, markets, and other stakeholders. In doing so, it will improve load factor, lower system losses, optimize asset utilization and avoid investments driven by "peaky" load and poor utilization. Planners and engineers will have the information to build what is needed, when it is needed, while more effectively managing capacity and resources on a day-to-day basis. Reliability will be improved through advanced outage management, distribution management and automation systems, geographical information systems and other technologies.

Achieving this vision requires a paradigm shift in what has traditionally been viewed as grid infrastructure, as well as the types of investments needed to achieve advanced functionality. Traditional utility investments focused primarily on upgrading and maintaining "electrical" infrastructure to ensure safety and reliability, increase capacity, and expand service to new customers. Customers were viewed as consumers of electricity, and the grid was designed to distribute power from large centralized generating plants to end-use consumers. Assets and investments have traditionally consisted of poles, wires, substations, and electrical equipment.

To achieve the promise of the Eco-Grid, investments in Information Technology (IT) and Operational Technology (OT) are needed to create an open, flexible platform integrating customers, competitive markets and service providers. Collectively known as "intelligence" infrastructure, these investments will include communication networks, sensors and control devices, and advanced information and management systems. Under this vision the Eco-Grid is not simply a newer, upgraded version of the legacy electric system, nor is it a specific technology or suite of technologies layered onto the existing utility systems. The Eco-Grid is instead the foundation of a larger ecosystem of customers, competitive markets and service providers who are interacting with the utility electric grid and the utility's information systems. Information and the exchange of information will be the lifeblood of this grid-connected ecosystem.

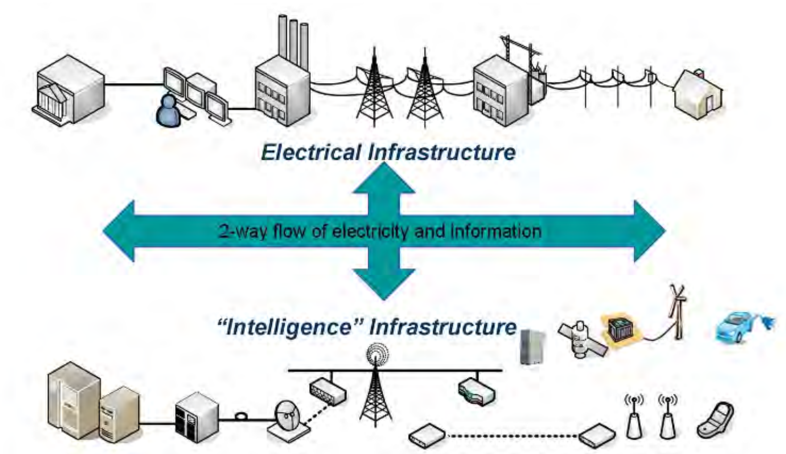


Figure 1: Electrical vs. Intelligence Infrastructure

2.3 Enabling Markets

As customers increasingly adopt new technologies including behind-the-meter generation, storage and energy management systems, the relationship between the utility and the consumer is changing. Customers are increasingly empowered to manage their energy use by taking full advantage of the information, market mechanisms, energy efficient technologies, diverse fuel sources, and transportation options available to them. In turn, our understanding of a utility "customer" must expand to encompass consumers, generators, prosumers (customers who consume electricity from and produce electricity onto the electric system), and other grid participants receiving or providing ancillary services. The Eco-Grid will support the creation of new electricity markets from home energy management systems in customers' homes, to technologies that allow consumers and third parties to bid their energy resources into wholesale markets.

Innovation will be the driving force behind new electricity markets and services, and will develop from information collected and maintained by the utility and shared externally with customers and service providers. The availability of this information will be crucial to the development of a more efficient and environmentally friendly grid. The Eco-Grid will provide a platform for customers to understand and actively participate in energy markets in order to enhance efficient utilization and consumption of electricity, while also supporting diverse activities by third parties. Grid operators will treat willing consumers as resources in the day-to-day operation of the grid. Well-informed consumers will modify consumption based on the balancing of their demands and resources with the electric system's capability to meet those demands.

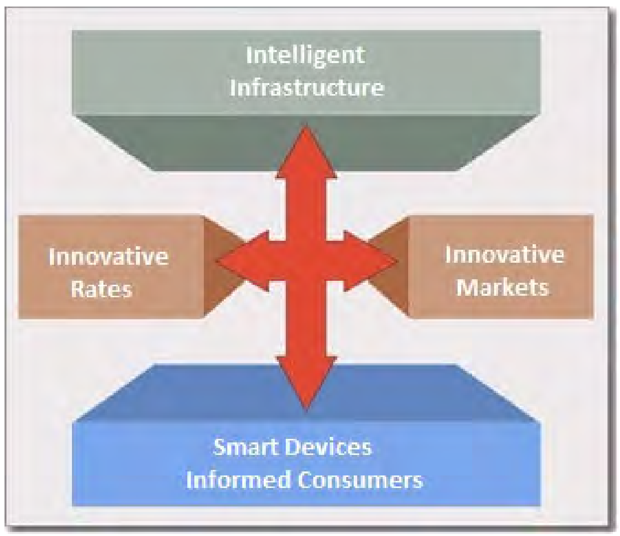


Figure 2: Enabling Markets

The grid of the future will be the foundation for a holistic energy ecosystem consisting of customers, competitive markets, third party providers and new technologies working together to achieve the promise of a clean energy future. Our vision is to create an ecosystem of innovation.

3 FOUNDATIONAL OBJECTIVES

So what will an advanced grid do differently than the legacy electric system of the past century?

- Deliver safe and reliable service meeting the expectations of today's customers, and the needs of a 21st Century economy.
- Engage customers and encourage their active participation in energy markets by enabling the easy adoption of new technologies and services so they can better manage their energy needs.
- Reduce the environmental impact of electricity generation by seamless integrating all types of generation and storage options, and by improving efficiency and optimizing demand.

- Support the interconnection and business models of third parties and encourage innovation.

The Company has identified a series of eight objectives that together ensure support of a modern energy ecosystem. Our objectives are crafted with guidance from the United States Department of Energy, New Hampshire Public Utilities Commission and Massachusetts Department of Public Utilities and are used to identify the investments and technologies that best serve this new era.

Examining these agencies and their goals revealed an emerging consensus around eight key areas of interest:

Objective 1: Environmentally Friendly – We must firmly support the region's goals in reducing emissions in the battle against climate change.

The Company unilaterally supports our region's stated goals to reduce emissions in supports of the battle against climate change. We believe utilities must enable the integration of renewable energy projects that will deliver emission-free solar, wind and hydro power to our region. We must also support energy efficiency and time-of-use initiatives which allow customers to take control of their own usage, further lowering emissions. We must educate and empower customers to shift their energy usage away from peak times of need, an action that not only provides substantial environmental benefits, but reduces overall demand and allows the system as a whole to operate more efficiently.

Objective 2: Safety and Reliability – We must continuously improve safety, reliability and resilience while reducing the effects of outages.

Providing safe and reliable service at an affordable cost to all customers is central to the Company's *Company Mission. The grid must be operated in a manner that ensures public and employee safety. Electricity must be delivered at a safe, stable, consistent voltage optimized for use by homes and businesses, and outages must be kept to a minimum. When storms do occur, the system must be built in a way that restoration can occur rapidly and efficiently.*

Objective 3: Customer Service – We must improve and embrace customer empowerment, engagement, and education. We must give the customer the tools they need to understand and control both their own energy usage and energy matters in the region.

As more and more at-home innovations evolve the way we use electricity, there is a growing customer need for a trusted energy advisor. Access to personal data on energy usage will help to empower customers to actively manage and understand their own technology and usage decisions, resulting in lower bills. Electric vehicles, heat pumps, smart appliances and energy management systems are changing the manner in which customers utilize energy and interact with the system. Home energy management systems require real-time information to help customers make decisions on how to optimize energy usage at home. Electric vehicle rate structures will help customers program when charging occurs and plan accordingly.

Objective 4: Security – We must ensure the cyber and physical security of the grid remains strong.

Strong cyber and physical security are cornerstones in ensuring the safety and reliability central to our Mission. The modern grid must reduce physical and cyber vulnerabilities while also enabling rapid recovery from disruptions. The secure sharing and rapid analyzation of accurate information will be central to a modernized energy ecosystem and the *development of new energy markets and services. Data security and customer privacy must be carefully integrated into existing operational practices.*

Objective 5: Flexibility – We must ensure the grid remains flexible enough to accommodate and integrate all types of new energy sources.

Small scale and large scale renewable energy projects are making the flow of electricity in cities and neighborhoods more complex. Managing this flow will require a smart, flexible system that not only makes interconnections easier for end-users, but allow system operators to rapidly switch over to utility-scale, reliability focused energy suppliers when required.

Objective 6: Affordability – Energy for life must remain affordable for all.

Ensuring fair prices is central to any modern grid design model. By ensuring our system infrastructure is a flexible, enabling platform, we are able to integrate customers with competitive markets and other service providers to enable the delivery of affordable energy choices for all. Such a system gives customers the opportunity to make decisions on how they use the grid, when they use the grid, and how best to maximize value.

Objective 7: Demand and Asset Optimization – The grid must be designed to get the most out of the tools and resources interconnected in order to best serve the region.

When renewable energy systems are connected to the system, we want to ensure interconnections are optimized for both the generator and end-users. The modern grid has advanced tools and technology in place to optimize system performance and improve the grid's performance from reliability, environmental, efficiency and economic perspectives. System demand is reduced through greater efficiency to control total system costs for generation, transmission and distribution. Advanced system planning tools will integrate the benefits of distributed energy resources and identify locations where these assets can be optimized. The objective here is to not necessarily operate all equipment to their ratings or limits. Rather, assets will be managed to only deliver what is required at the time. Real-time data will provide the information required to reduce operating and maintenance costs along with the environmental benefits associated with improved efficiency and fewer failures.

Objective 8: Technology Innovation – The grid must enable the easy adoption of new technologies as they are developed to further support customer choice and system operations.

Effective technology and secure data sharing is crucial to operating a transparent and open energy system. Customers and other users want to make informed decisions on their energy needs, and data from the Energy Hub makes sharing simple and intuitive. Developers, meanwhile, need clear rules for how to interconnect renewable energy projects as well as an understanding of where interconnections would maximize the value to the system.

There are inherent complexities and challenges associated with supporting each objective individually without considering the whole. Offering customers more technologies and increased data sharing can potentially increase risk of cyberattacks, which in turn creates security challenges. The early adoption of some emerging technologies can come at a premium, and associated costs create conflicts with the goal of keeping energy affordable. The intermittent nature of some forms of renewable energy sources can be at odds with the reliable service our customers expect. The list goes on.

It is in recognizing the push and pull these objectives have on one another where the maximum benefit to all customers can be found. The system must be operated in a manner which optimizes the benefits for all while ensuring all voices and viewpoints are heard and represented. Balancing all objectives is the key to unlocking this utility future state we aspire towards.

4 ROADMAP TO THE FUTURE

The roadmap to the future is a journey that must be planned carefully and executed in a precise manner. It is not a sprint to implement technology just to have that technology become obsolete in two years. Some technology will serve as a foundation to other technologies. Implementing the building block of the advanced grid in a well thought out manner creates the enabling platform that is the basis for the Company's vision.

The Company has identified six categories of technologies required to develop the grid as an enabling platform.

1. Grid Intelligence
2. Advanced Metering
3. Distributed Energy Resources
4. Advanced System Planning and Forecasting
5. Enhanced Customer Services
6. Innovative Rate Design

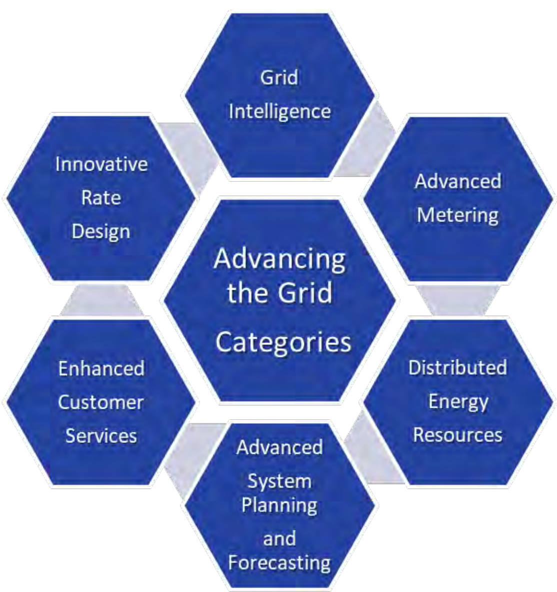


Figure 3: Advancing the Grid Categories

4.1 Category 1 - Grid Intelligence

The modern electric system is changing at a rapid pace with the integration of distributed, variable and renewable resources combined with the focus on electrification of the transportation and heating sectors. New and different users are connecting to the system every day. The ever increasing levels of these resources will have a significant impact on the safe, reliable and cost effective operation of the distribution system. Increased visibility and control deep into the distribution system is quickly becoming a necessity. System optimization and efficient use of the grid resources is increasingly more important in providing a safe, reliable, sustainable and cost effective electric system.

Grid Intelligence technologies rely upon a safe and reliable advanced communications system to provide communications for the monitoring and control of field devices. The Company's Grid Intelligence vision consists of centralized software systems and the installation of field devices for Advanced Distribution Management System (ADMS), Distributed Energy Resource Management System (DERMS), Outage Management System (OMS), Supervisory Control and Data Acquisition (SCADA), Volt/VAr Optimization (VVO) and further integration of the Advanced Metering Infrastructure (AMI).

An **ADMS** is the next step in the evolution of distribution management systems. An ADMS is a complex software platform that will serve as the primary means for managing the distribution system. The ADMS will integrate the Company's previous investments in AMI, OMS, SCADA, Geographic Information System (GIS), Customer Information System (CIS), Meter Data Management System (MDMS), circuit analysis, and load flow analysis systems together to provide all of the information in one location. An ADMS integrates a comprehensive set of monitoring, analysis, control, planning, and informational tools that work together with one common network model to provide real-time status and control of the distribution system and the resources connected to it.

A **DERMS** provides the Company with the ability to monitor and control certain distributed energy resource (DER) installations across our service territory. This technology is implemented as a module within the ADMS. The technology improves real-time situational awareness and operational intelligence for this increasingly important resource. The DERMS is used by grid operators and engineers for efficient grid operations and planning by providing real-time information resulting in an increased amount of DER which can be safely interconnected to the system.

An **OMS** is the primary system the Company uses to monitor and coordinate the Company's response to outage conditions. This technology is implemented as a module within the ADMS. The OMS collects customer outage tickets and uses an algorithm to predict the size of the outage, the customers involved in the outage and the predicted device that isolated the fault. The OMS also estimates estimated restoration times and provide outage and restoration estimate to customers as well as the customer outage map. The OMS is the Company's primary communication to customers during an outage event.

SCADA provides the Company with the means to centrally monitor system operating conditions in real-time and remotely control field devices. SCADA at the distribution level is implemented as a module within the ADMS. The industry has historically had good SCADA coverage of transmission systems and substations but less comprehensive SCADA deployment on distribution systems. Grid modernization of the distribution system will require more extensive real-time monitoring and remote control throughout the distribution system.

VVO is a technology applied on the distribution system to monitor and control system voltage within a smaller range resulting in energy and demand savings for customers. This technology is implemented as a module within the ADMS. VVO uses real-time system data to control voltage regulators and capacitor banks to fine-tune distribution voltages across the system. VVO's ability to monitor the grid conditions also improves the ability to reliability and cost effectively interconnect wind, photovoltaics (PV), electric vehicles (EV) and other DER to the electric system. VVO technology provides a unique type of energy efficiency and demand reduction which does not require the customer to take any action or change their usage behaviors to experience the benefits. Studies have shown that effective VVO installations can reduce energy consumption and demand by 2-4 %, which translates to savings in transmission and generation charges as well as deferral of capacity related distribution improvements.

The Company's **AMI** system provides information on outages for every meter on the system. Improved integration of outage information from AMI meters into the OMS outage prediction engine improves the outage prediction process, reduces false positives and improves the ability to identify the location of nested outages. The Company is developing a piece of configurable "middleware" (i.e. software) to analyze AMI status changes along with additional relevant data points, and computing an "AMI Confidence Score" for AMI based customer outage reporting. Based on the configuration of the middleware, suspected outages above the allowed "score threshold" will be treated as "real outages" and reported to OMS as such. Those that fall below the threshold will be logged and sent to OMS for view only. The system will leverage a set of correlating data inputs such as historical outages, low level signal data, and weather data along with machine learning models to assist in computing outage confidence.

The implementation of a **FAN** is an enabling technology that is a critical component in enabling the benefits associated with grid modernization. A FAN provides the Company with the communications backbone to install many of the grid modernization initiatives being considered. The FAN will provide the customer benefits of reduce outage frequency and duration, enhanced security, improved visibility and allow the integration of DER. The FAN enables a diverse set of grid modernization technologies such as ADMS, VVO, SCADA, demand response, DERMS, EV charging stations, data sharing as well as other technologies.

The **mobile platform damage assessment system** will be an application based system that will replace existing paper based damage assessment and inspections presently used by the Company. This system will allow damage to be collected on the mobile application including the location, the type of damage and pictures. This data will automatically be transferred back to the back end system portal in the office where ETRs and work packages can be developed, issued for repair, tracked until completion.

The safe and reliable operation of the electric system has become more challenging. **Distribution Automation (DA)** has become more popular with the changing landscape of intermittent loads and generation sources connecting to the disturbing system. DA refers to the intelligence of the distribution system that uses information from other devices on the distribution system to identify problems and take action to alleviate the concern. DA can take the form of automated switching and self-healing routines to restore power following an outage. DA can be used to reconfigure the system to optimize system loading and reduce losses. DA is used to manage power factor compliance and improve power quality. DA can take a lot of different forms, but it requires field edge equipment in communication with centralized software to implement the system changes.

4.2 Category 2 - Advanced Metering

The information age has given us the ability to have data in the palm of our hands and when we want it. The satisfaction of having a world of information at our fingertips has changed the way we communicate, surf the web and shop. We have become accustomed to get news alerts as events are unfolding, up to date stock trading information, and accurate weather forecasts. The world is driven by data.

The modern electric system is also driven by data and information. Customers need data to inform their usage decisions. They need flexible pricing options that allow them to take advantage of their investments. Customers need to know how much electricity they are using and when that electricity is being used. Customers are willing to reduce their peak hour usage as long as they have the knowledge and tools to achieve the benefits. Timely and user-friendly data starts with a metering system that can accurately and automatically gather granular usage data, store the data in a meter data management system where it can be pushed to customers in a timely manner.

Advanced Metering Functionality (AMF) refers to the capabilities provided by the metering system. AMF provides the platform for the Company to measure and provide detailed and granular interval metering data of each individual customer. AMF may provide data in real-time or near real-time, or on a daily or monthly basis. AMF data provides the information necessary for demand management programs, time of use or time varying rates, and other customized programs focused on controlling or reducing energy consumption.

AMI allows the Company to continue to achieve savings in reduced staffing, provide more timely and accurate bills, eliminates the need for additional truck rolls to read meters, allows for virtual turn-ons and turn-offs which reduces labor costs, results in fewer billing complaints and allows disputes to be resolved faster, provides timely outage information which reduces overall restoration time, and its tamper and theft related tools reduces the cost of lost revenue. These cost savings have been and continue to be shared with customers on an annual basis.

The Meter Data Management system collects, organizes and presents a vast and diverse set of metering data. Customer usage patterns can vary with the time of day, day of the week, and time of the year. Load can be influenced by weather or by the economy. Every customer is different, and the granular data provided by interval metering is helpful for customer engagement efforts and developing products and programs to benefit the customer and the system by adjusting usage patterns. AMF can empower customers to take control of their own usage through bill alerts or individualized customer education.

4.3 Category 3 - Distributed Energy Resources

The growing penetration of variable loads and intermittent renewable resources creates a challenge for the electric system if the grid is not prepared to accept these resources. The Company's vision of the advanced grid is an enabling platform with the ability to interconnect a large quantity of renewable resources and other Distributed Energy Resources.

New Hampshire (NH) has not experienced the quantity of Distributed Energy Resource interconnections that Massachusetts has. In Massachusetts (MA), the Company's affiliate Fitchburg Gas and Electric Light Company ("FG&E") continues to experience a high penetration of DERs. DERs are electricity producing resources or controllable loads that are connected to the distribution system. The quantity and capacity of DERs across the service territory has created reverse power flow conditions that require system improvements for capacity and system protection. Across our service territories in MA and NH combined, the penetration of generation is approaching 25% of peak load and 80% of light load. Generation accounts for over 50% of the peak load, and totals over 160% of the measured light load when focusing on our Massachusetts service territory alone. The Company expects to see an increased interest in interconnections in its New Hampshire service territories in the near future and is implementing advanced monitoring and control technology solutions (such as ADMS and DERMS) to enable this large amount of DERs and operate a safe and reliable system. There may be other projects that are required to address DER reverse power flow and sustained energization mitigations.

The Company's affiliate, FG&E, owns one utility scale solar installation, Solar Way, located in Massachusetts. Solar Way, a 1.3MW solar facility, provides enough electricity to serve an equivalent of over 800 residential homes. FG&E is using this installation as a pilot and continues to evaluate opportunities to install additional utility scale solar in areas of the system that may benefit from the additional capacity.

FG&E is currently installing a 2 MW/4MWh utility scale energy storage system at a substation in its Massachusetts service territory to defer the need for a costly substation expansion. The energy storage system has the ability to serve over 1,300 homes for over two hours. This energy storage system is designed to reduce peak loading on the substation equipment, as well as provide voltage regulation and frequency regulation to the market. This is a significant size energy storage device measuring over 2% of the system peak for the Massachusetts service territory. FG&E is using this installation as a pilot and continues to evaluate opportunities to install additional utility scale energy storage in areas of the system that may benefit from the additional capacity.

Energy Efficiency (EE) also plays a key role in an environmentally friendly grid. The energy efficiency programs the Company offers to its customers are developed as part of a comprehensive, statewide approach to optimizing energy use by electricity and natural gas customers. These efforts aim to transform the marketplace for energy-using services and equipment in the built environment by working with distributors and retailers, building and installation contractors, and end use customers in the commercial, industrial, and residential sectors. The Company has pursued cost effective EE in support of annual energy saving goals established through a robust stakeholder process. EE programs are informed by nearly two decades of experience working with stakeholders, consultants, our colleagues at the other gas and electric utilities, as well as our customers. Our internal EE staff of more than a dozen planners, implementers and administrators work across jurisdictions (i.e., in Massachusetts as well as New Hampshire) and is supported by a broad complement of vendors, contractors, builders and evaluation firms, all with in depth knowledge of demand side efficiency and conservation. By moving consumers and contractors away from less efficient products and appliances, our incentives continue to transform the market for lighting and equipment and train customers to consider not just up-front cost but lifecycle costs.

The Advanced Grid has the ability to plan for, monitor and control a diverse set of distributed assets on the system all designed to support the safe and reliable operation of the electric system. Advanced monitoring and control technology evaluates the system in real-time and issues control commands to optimize the system. An environmentally friendly grid is one that is optimized for interconnection and use of renewable resources while optimizing the system demand at all times of the year. The Advanced Grid needs to be flexible enough to integrate increased amounts of renewable energy and use these resources to optimize the system and minimize GHG emissions.

4.4 Category 4 - Advanced Planning and Forecasting

The growing penetration of variable loads and intermittent renewable resources creates a challenge for the electric system if the grid is not prepared to accept these resources. The Company's vision of the advanced grid is an enabling platform with the ability to interconnect a large quantity of renewable resources and other DERs. Advanced system planning forms the foundation for an enabling platform able and ready to accept DERs and other electrification technologies.

Advanced system planning begins with an accurate system model. Geographic Information Systems that are maintained on a timely basis form the network model used in Advanced System Planning. A complete and detailed network connectivity models is essential and is used across multiple platforms allows for consistent results for real-time operation of the electric system.

Real-time system planning is foundational to the optimization of the electric system. The modern grid is constantly changing. Intermittent generation resources and added loads from electrification can drastically change operating conditions within moments. Real-time system planning provides grid operators the tools to make the necessary adjustments to optimize the system. Real-time system planning increases the safety, reliability and security of the electric system.

Forecasting is a critical component of advanced system planning. DER interconnections can be a challenge to the electric system if they are not planned for. DER forecasting enables the electric system to take advantage of DERs for the operation of the system. DER forecasting can identify the real cost of DERs in comparison to traditional alternatives and drive a lower cost and improved affordability across the system. Electrification has the potential to double the electric loads on the electric system. Increased adoption rates of electric vehicles and heat pumps have the opportunity to have a negative effect on the electric system if the loads are not accurately forecast and included in system design and operation considerations.

DERs can be a challenge and a benefit to the electric system. Advanced system planning reduces the risk associated with DER interconnections and enables the benefits to be realized by the system and customers. Hosting capacity and locational value analysis are tools that can be used to identify the optimal locations for DER interconnections maximizing the benefits to the customers and the system. Understanding the value and benefits of DERs will allow utilities to plan for and rely-on cost effective DER solutions to defer distribution system upgrades.

4.5 Category 5 - Enhanced Customer Services

Superior customer service is fundamental to the Unitil Corporation's Vision, Mission and Values. In 2020, Unitil Corporation's 93% overall customer satisfaction results were the highest in our history and significantly higher than most of our peers. From a benchmarking comparison perspective, we ranked 10th out of 114 measured utilities nationally, 2nd out of 23 utilities in the Eastern Region and the 1st rated utility out of our peers in the Northeast. We earned these high levels of satisfaction by recognizing our customers' increasingly diverse and complex needs.

Our energy efficiency programs help customers make smart financial decisions by reducing energy usage during periods of peak demand. By reducing our customers' overall energy consumption and demand during peak periods, our EE programs contribute to the reduction of greenhouse gas emissions within the communities we serve.

Looking forward, we will continue to invest in technologies designed to support our commitment to the customers experience and to their satisfaction in all facets of that experience. We will strengthen current service offerings, make enhancements to our customer web portal, and add self-service options that enable customers to better manage their energy usage and accounts. These planned enhancements include a mobile app, artificial intelligence and chat features, and a robust notification engine to proactively alert customers regarding payment activity, changes in usage patterns, outages, and scheduled appointments.

4.6 Category 6 - Innovative Rate Design

The Company strongly believes the overarching objective of rate redesign should be the development of pricing for grid services that adhere to the principles of fairness, transparency and economic efficiency.

Only through transparent and economically efficient pricing structures will a viable and sustainable long term model be developed that provides sufficient revenue to support the significant investments needed to modernize the grid, while encouraging appropriate behaviors and assuring fairness and equity among customers. We continue to review how rate design must evolve to enable customers to more effectively manage their energy needs.

We are also reviewing programs that will best support our customers' requirements as we continue to advance the electric grid. Time-of-Use (TOU) and Distributed Generation (DG) rate structures, for example, may support future rate reform. Innovative rate designs will afford our customers the opportunity to adopt new technologies, manage their energy consumption and actively participate in energy markets to enhance efficient utilization and consumption of electricity and save money. Implementing technologies and programs to facilitate these activities will make the electric system more efficient, economic and environmentally friendly.

5 MAPPING OF CATEGORIES AND PROJECTS/FUNCTIONALITIES TO OBJECTIVES

The next step of this plan is to map the categories and projects/functionalities to the objectives that have been presented in the previous section of this report. This mapping process is a key component to ensure the projects being recommended directly support the defined objectives. Appendix A of this plan maps the categories and projects/functionalities to the objectives. This mapping ensures that the functionalities of the distribution system are tied back to specific objectives. This section of the report will further describe each category and how the projects and functionalities map back to the objectives.

5.1 Grid Intelligence

The modern electric system is changing at a rapid pace with the integration of distributed, variable and renewable resources combined and the focus on electrification of the transportation and heating sectors. New and different users are connecting to the system every day. The ever increasing levels of these resources will have a significant impact on the safe, reliable and cost effective operation of the distribution system. Increased visibility and control deep into the distribution system is quickly becoming a necessity. System optimization and efficient use of the grid resources is increasingly more important in providing a safe, reliable, sustainable and cost effective electric system.

Grid Intelligence technologies rely upon a safe and reliable advanced communications system to provide communications for the monitoring and control of field devices. The Company's Grid Intelligence vision consists of centralized software systems and the installation of field devices for ADMS, DERMS, OMS, SCADA, VVO and further integration of AMI.

5.1.1 DESCRIPTION

The Company manages its distribution system with limited control and visibility beyond the distribution substations. Limited tools are available to monitor and control the influx of intermittent renewable resources causing two-way power flows. These resources have a substantial impact on reliable operation of the system. This limitation is not congruent with the needs of real time grid operations and distributed resources on the network. The Company's Grid Intelligence vision includes the technology to provide real-time visibility into the vast majority of the distribution resources connected to the network.

The Company's Grid Intelligence vision consists of the following technology advancements: FAN, ADMS, DERMS, OMS, SCADA, VVO, and further integration of AMI and OMS.

5.1.1.1 Field Area Network

There are many different technology options for a FAN such as wireless mesh, point-to-point fiber, point-to-point POTS line, radio, and microwave, and carrier networks. The Company has evaluated the strengths and benefits of the different types of communication technologies.

Based upon the bidding evaluation, the Company decided on the carrier solution for our field communications. The Company will utilize the AT&T FirstNet network in New Hampshire and Massachusetts. AT&T FirstNet is a nationwide high-speed wireless network reserved for use by public safety and emergency first responders. It is designed to allow essential workers and emergency first responders the ability to communicate across a network that is separate from the communication paths used by the general public. This network also comes with a higher service level agreement that gives it priority if repairs are required. For applications where reliability and redundancy is critical, the Company has an existing contract with another carrier vendor for private area network services and would install redundant communications at these locations. The implementation of the communications network can be accomplished over time, which aligns well with the Company's approach to grid modernization.

5.1.1.2 Advanced Distribution Management System

An ADMS system provides many different functions such as (but not limited to) self-healing automation, control for distributed energy resources, additional SCADA functions across the distribution system, real-time load flow and circuit analysis, demand response, outage restoration, direct load control, network configuration, and integration of outside data sources such as real-time weather and VVO. The ADMS provides the visibility and control required to operate a safe and reliable electric system. The ADMS also provides valuable information during outage events and enhance situational awareness resulting in shorter outage durations.

The Company's ADMS system will be implemented with the following functionalities:

- GIS editor to transfer the network model from the GIS system to the ADMS system on a routine basis as changes to the network topology are made in GIS
- Verification of network connectivity
- Integration with existing OMS and SCADA systems
- Switching manager and simulation module
- Volt/VAr Optimization
- Crew assignments
- Engineering based load flow and circuit analysis tools
- Hardware, software, and training

An ADMS system is closely integrated with other enterprise systems to realize its full potential, such as the FAN to provide communication to field devices, the installation of field devices that have the ability to be controlled and a DERMS that provides the monitoring and control of DERs connected to the system.

This complex project will take several years to implement, but it will serve as one of the foundational technologies to achieving the objectives described below.

5.1.1.3 Distribution Energy Resource Management System

DERMS functionality can be implemented as part of an ADMS or as a separate stand-alone system. The Company is already implementing an ADMS system that has the capability to offer DERMS functionality. One benefit to integrating the ADMS and the DERMS is to have one system and one network model used to operate and optimize the system.

DERMS technology will improve situational awareness and operational intelligence for this increasingly important resource. DERMS will be used by grid operators and engineers for efficient grid operations and planning.

DERMS would use real-time information communicated across the FAN to monitor, control, and manage distribution assets across the electric system. These resources include: large scale as well as residential solar installations, wind, energy storage, microgrids, demand response and other DER connected to the system. The DERMS will have the capability to control grid connected devices by changing voltage and power flow settings in individual devices. These types of devices can include: voltage regulators, smart inverters, capacitor banks, load tap changers, electric vehicle charging, and controllable end-user loads.

This project consists of developing a DERMS to monitor and manage DER across its service territory. The technology will improve situational awareness and operational intelligence for this increasingly important resource. Currently, the Company does not know when individual DERs are operating, since many of these installations are net metered rather than having their generation metered separately. This dynamic makes it difficult to develop accurate models for engineering analysis and planning. DERMS will be used by grid operators and engineers for efficient grid operations and planning.

DERMS functionality can be used to control and optimize small localized segments of the electric system or entire feeders at a time. For example, the DERMS will monitor every segment of the electric system to determine if the system has too many DERs or could accommodate, more DERs depending on the time of year and system loads. The system will know exactly what actions to take to alleviate the situation.

Smart inverter standards and technology has made huge strides in the past several years. Smart inverters allow real-time control of voltage output, power output, power factor and even frequency. A DERMS has the ability to dynamically control these settings to optimize system operations.

5.1.1.4 Outage Management System

The Company implemented an OMS many years ago. In evaluating the implementation of an ADMS, the Company decided that implementing a single platform that integrates the various technologies would be the most efficient and effective way of managing the system. The Company selected the vendor of its OMS system to provide the ADMS system.

The OMS uses the same detailed network model as ADMS, DERMS and VVO. This ensures that the model is consistent and the systems can operate with the most up to date data. OMS systems are designed to reduce outage duration due to faster restoration based upon outage predictions, prioritizes outages for restoration, improves customer satisfaction due to an increase awareness of restoration progress and restoration times, improved customer and municipal relations by providing accurate and timely outage information, and reduced outage frequency due to the use of outage statistics to implement reliability improvements.

The OMS uses a combination of customer calls from the IVR system, web based outage reports and SCADA information to predict where the outage is located, which customers are affected and estimate an ETR based upon similar outages in the past. The Company reports outage information directly to customers and to the public through email, text and a live web based outage map.

Model accuracy is important to ensure the prediction engine will provide accurate outage predictions. The Company ensures the accuracy of its OMS through software integrations with many other enterprise systems. The Company's OMS system is integrated with: 1) GIS to provide the electric system network topology; 2) CIS system to provide customer related information; 3) IVR system to receive customer outage calls; 4) ADMS to provide system modeling for outage restoration; 5) SCADA to provide outage information and remote switching capability; 6) AMI to provide outage information to better inform the prediction engine; 7) outage reporting web map for public facing outage information; 8) web based outage reporting for those who do not wish to call into the IVR system; and 9) reliability reporting system.

5.1.1.5 Supervisory Control and Data Acquisition

SCADA is a control system architecture that allows the Company to monitor system conditions and operate field devices from the central office. SCADA uses the advanced communications network as the means of passing commands to and receiving data from devices located throughout the distribution system. The SCADA system provides real-time monitoring of system conditions and alarms when an abnormal event has occurred such as an unexpected overload or outage.

The Company has historically installed SCADA on its transmission and substation infrastructure but has limited SCADA installed on the distribution system. The Company will transition its SCADA system to the ADMS to provide consistency in the user interface for system operators as well as the confidence in model accuracy because all systems will be using the same network model. The Company's vision is to continue to expand SCADA across the distribution system where it makes sense when installing VVO and distribution automation schemes.

Cyber security of the SCADA system is of critical importance to the safety and reliability of the electric grid. More expansive deployment of SCADA functionality and integration of SCADA with other systems increases the potentials for cyber security risk. The risk could be direct control of field devices by unauthorized access or an altering of real-time information from the field to the central office resulting in an inaccurate evaluation of the current status of the grid. The reliable function of the SCADA system is critical to public safety and reliability of the grid. The Company has designed the SCADA system with appropriate cyber protections to support the security and resilience of the SCADA system. This same cyber design extends to all the ADMS modules as well.

5.1.1.6 Volt/VAr Optimization

Utilities have traditionally used local control to operate voltage regulators, substation Load Tap Changers (LTCs), and distribution capacitor banks to control voltage and power factor across the distribution system. These devices incorporate inputs from locally available measurements and accommodate a wide range of operating conditions from peak load conditions to light load conditions. These devices act independently of other devices on a given circuit or feeder, which may result in suboptimal affects across the circuit.

There are three primary aspects to implementing a VVO program: communications, software intelligence and field equipment. A robust communications network is the foundation for a successful VVO program. A communications network will be designed to support the VVO program and the software intelligence will be provided as part of the ADMS. The field equipment will be equipped with controls which will allow the VVO system to monitor and control those devices.

Technology has improved to the point where implementing VVO equipment and software can reduce line losses, energy consumption and demand by optimizing the distribution system voltage. Circuit optimization is affected by many different factors across the circuit such as substation bus voltage, end of line voltage, types and sizes of loads, length of feeder and type of conductors, as well as the size, quantity and type of DER located on the circuit. The ever-changing load and DER conditions make optimizing a circuit very challenging.

VVO utilizes dynamic operating model of the system in conjunction with real-time information from the field and analyzes this information through a complex algorithm to optimize the performance of the distribution system. The system model and algorithm combined with real-time field measurements and control enable the circuit to be optimized based upon minimizing power loss or demand while maintaining acceptable voltage profiles on each distribution circuit.

5.1.1.7 OMS/AMI Integration

The Company's OMS system relies on customer outage calls processed by the IVR system, web outage form entries, and manual entries of customer and municipal calls to predict the location and extent of outages. Most outages are reported by only a small percentage of customers contributing to the outage information (typically, only 1-2% of the customers notify The Company when they are out of power). This small percentage of customer notifications may lead to an erroneous outage location and extent, or delay the field trouble shooting process.

The Company's AMI system is currently integrated with OMS as a “view only” overlay. The AMI system communicates with all meters through a parallel channel powerline carrier system. Essentially, the system continuously communicates with all the meters on the system while data collectors in the substations transmit meter status to the head end software system called the Command Center. Changes in meter status are shared through live integration with the OMS where they can be visually represented. Communication with meters could be lost for reasons other than an outage (e.g., noise on power line, loss of AMI network communications). Therefore, the Company does not use this information in the algorithm for modeling outages in OMS. Instead, the visual AMI information is presented in OMS to help determine the extent of the outage (i.e. all outage meters go "lost" or red when they lose power) and the extent of restoration (i.e. all restored meters restored become "found" or green).

This project combines AMI status information, modem status information, and current outage input data (IVR, Web, and manual entries), and process this information through a series of software filters and logic to allow AMI information to be used in the outage prediction algorithm. The goal is to develop a filter to the point at which there is high confidence in the result (i.e., the AMI status change is a result of an actual outage). If a high confidence is achieved, the AMI data will allow the Company to determine the probable location and extent of an outage in a shorter timeframe, resulting in improvements in outage response time estimates and related customer communications.

5.1.1.8 Mobile Damage Assessment

This project is to implement a Mobile Damage Assessment Platform to enable quicker, better-informed decisions to ensure operational efficiency and maintain strong restoration performance by significantly reducing the amount of time for field information to be relayed. This would allow for faster and more accurate situational awareness during large scale weather events.

The project team developed an RFP and received proposals from 13 vendors which were discussed and evaluated. The application will expedite damage data acquisition, develop faster ETR’s, enhance overall situational awareness and produce more efficient work packages that will, in turn, expedite the overall restoration.

The mobile platform damage assessment system will be an application based system that will replace existing paper based damage assessment and inspections presently used by the Company. This system will allow damage to be collected on the mobile application including the location, the type of damage and pictures. This data will automatically be transferred back to the back end system portal in the office where ETRs and work packages can be developed, issued for repair, tracked until completion.

5.1.1.9 Distribution Automation (DA)

The safe and reliable operation of the electric system has become more challenging. Distribution Automation (DA) has become more popular with the changing landscape of variable loads and intermittent generation sources connecting to the distribution system. DA refers to the intelligence of the distribution system that uses information from other devices on the distribution system to identify problems and take action to alleviate the concern. DA can take the form of automated switching and self-healing routines to restore power following an outage. DA can be used to reconfigure the system to optimize system loading and reduce losses. DA is used to manage power factor compliance and improve power quality. DA can take a lot of different forms, but it requires field edge equipment in communication with centralized software to implement the system changes.

5.1.2 MAPPING TO OBJECTIVES

The Company has developed a set of objectives influenced by the United States Department of Energy, Massachusetts Department of Public Utilities and New Hampshire Public Utilities Commission. Examining guidance provided by these agencies reveals an emerging consensus around certain key areas of interest. The benefits and values achieved from the modern grid can result in cost savings for all users. This section identifies how the Grid Intelligence vision supports the objectives established by the Company.

Project/Functionality	**Existing / Planned**	**Safety and Reliability**	**Customer Enablement**	**Security**	**Flexibility**	**Affordability**	**Demand and Asset Optimization**	**Technical Innovation**	**Environmentally Friendly**
Field Area Network	Planned	X	X	X	X	X	X	X	X
Advanced Distribution Management System (ADMS)	Planned	X	X	X	X	X	X	X	X
Distributed Energy Resource Management System (DERMS)	Planned	X	X	X	X	X	X	X	X
Outage Management System (OMS)	Existing	X	X					X	
Supervisory Control and Data Acquisition (SCADA)	Existing	X	X	X	X	X	X	X	X
Volt/VAr Optimization	Planned	X	X		X	X	X	X	X
OMS/AMI Integration	Planned	X	X					X	
Mobile Damage Assessment	Planned	X				X	X	X	
Distribution Automation	Planned	X	X	X	X	X	X	X	X

Table 3: Grid Intelligence Mapping

5.1.2.1 Safety and Reliability

Grid Intelligence is a critical element to operating a safe and reliable distribution system. Information and communication technologies are used to optimize the system and support decision making to improve system performance. Grid Intelligence of the distribution system voltage will improve the overall safety and reliability of the distribution system. Grid Intelligence technology will assist operators, as the system becomes more complex and less predictable, to interpret data and information, predict conditions and make quicker decisions to ensure the reliability and safety of the electric system.

The growing penetration of variable loads and renewable intermittent generation assets creates a challenge for the electric system. Grid Intelligence systems have the ability to manage and compensate for loads and intermittent resources connected to the system. Grid Intelligence systems are capable of managing load to control or prevent reverse power flow conditions and reduce the opportunity for protection issues related to ground overvoltage conditions. Real-time monitoring will provide for improved situational awareness. Forecasting and modeling capabilities will allow operators to plan for near term and longer term system requirements. Remote switching and fault locating capabilities can reduce the overall size and duration of an outage to minimize impact to customers. Grid Intelligence systems become the primary tool of the system operators to monitor the overall health and condition of the electric system and the ability to safely and reliably respond to events that could pose a risk to the system or its customers.

5.1.2.2 Customer Enablement

Grid Intelligence is a critical component to enabling the continued growth of DERs and the two-way power flows while maintaining a safe and reliable system. In addition, Grid Intelligence provides the real-time situational awareness to support and facilitate an increased amount of DERs on the electric system.

Grid Intelligence system are designed to optimize system voltage and power factor to reduce system losses, customer consumption and demand. Grid Intelligence also allows for improved voltage control while supporting two-way power flows. Grid Intelligence will provide the optimization and control required to support the interconnection of intermittent renewable resources as well as additional electrification opportunities. Grid Intelligence is a completely transparent way for customers to achieve energy savings without taking any action.

Grid Intelligence will empower customer choice and demand side flexibility such as PV, energy storage systems, electric vehicles and demand response resources. Grid Intelligence will support the electrification of the transportation and heating sectors providing the operators the ability to monitor and control power flows to optimize the system resources.

Grid Intelligence systems provide valuable information to support data sharing between the utility and its customers to empower the customers to change their usage behaviors that will benefit the system and reduce overall costs. Grid Intelligence will help to facilitate energy markets at the distribution level by operating the system in a manner that optimizes the performance and reduces costs.

5.1.2.3 Security

Grid Intelligence is designed to maintain physical and cyber security for the electric system and its customers. Capacity ratings specify the physical limitations of the distribution equipment. Grid Intelligence will control the amount of power flow allowed through every device to physically protect the system from overloads. The Grid Intelligence systems are also designed to identify and report tamper or physical attacks on the system, notifying the operator to take action. Grid Intelligence relies on wide area and field area networks to enable the monitoring and control functionality of field devices. Introducing DERs and customer loads exposes more points of potential cyber risk. Grid Intelligence will be implemented with comprehensive cyber-security measures built into the architecture and integrated into operational procedures to quickly identify, isolate and minimize any cyber threats.

5.1.2.4 Flexibility

The electric grid will be designed in a flexible manner allowing the interconnection of renewable intermittent resources in a safe and reliable manner. An over-abundance of renewable generation can, from time to time, cause voltage fluctuations and result in high voltage for certain parts of the system. Grid Intelligence provides the ability to monitor, control and compensate for the intermittent nature of renewable resources and optimize their benefits to the system and lower the overall operating costs. The automation afforded by the DERMS and ADMS allows the system flexibility to interconnect and safely control a large set of diverse resources. Grid Intelligence empower customer choice and demand side flexibility such as PV, energy storage systems, electric vehicles and demand response resources. Grid Intelligence has the flexibility to support operations and allowing for secure local and remote access if necessary.

Optimized electric systems have the flexibility and responsiveness needed as the distribution systems evolve towards an architecture that encourages DG adoption. Grid Intelligence has the ability to optimize the distributed assets on the system to optimize the system and support the requirements of the system. The VVO system will provide the control and stability to react to varying usage characteristics while maintaining the flexibility to alleviate location specific power quality concerns at any given time of day, week or year. More efficient system operations provide the system operators with a greater flexibility to address grid resilience.

5.1.2.5 Affordability

In the near future, the distribution system will see some major changes in the products and services it provides. Markets and pricing mechanisms will be in place for customers to receive payments or credits for allowing their equipment to participate or be controlled in certain programs aimed at optimizing the system. Grid Intelligence solutions will continue to adapt to gain the most value out of DERs connected to the system. Grid Intelligence solutions position the Company to participate in the new business models and policy changes that are on the horizon. Grid Intelligence reduces the cost of ownership through improvements to reliability, efficiency and system optimization and provides customer access to a larger market at the distribution level.

VVO is a cost-effective way to provide energy efficiency benefits to customers without the need to recruit participants. VVO produces benefits on the customer side of the meter as well as on the distribution system. One of the primary benefits of a VVO system is the ability to reduce consumption, demand and losses. The VVO system provides direct and immediate savings on customer bills due to the reduced consumption and reduced transmission and generation charges. Optimizing the system will have a tendency to reduce and shift the peak loads and defer the need for capacity related system improvements. The system's ability to allow increased DG penetration on the system will provide customers with the ability to make their own choices.

The distribution system must be operated in an optimized manner to gain the most value while also making it affordable. Grid Intelligence is the platform to optimize and maximize the performance of the system at the lowest cost. Grid Intelligence is designed to improve reliability and minimizing the impact of outages resulting in reducing the costs associated with outages.

5.1.2.6 Demand and Asset Optimization

An optimized electric system only uses what it needs at any given moment in time. Grid Intelligence provides system planning tools to integrate the benefits of distributed energy resources and identify the location where these assets can be optimized. Grid Intelligence uses information from grid edge devices and sensors to monitor and reduce system demands where practical to control total system costs for generation, transmission and distribution. Grid Intelligence provides the information and control of the system to manage system loads and optimize the integration of distributed, variable, and renewable resources in a manner to defer traditional investments and to offset the need for the system improvement. Assets in the field are managed in a way to schedule maintenance as needed and avoid unnecessary maintenance. Grid Intelligence provides real-time data to reduce operating and maintenance costa along with the environmental benefit associated with improved efficiency and fewer failures.

The DERMS in conjunction with the ADMS are key components to enabling a system that can be optimized for various different conditions such as voltage, load, losses, renewable generation, energy storage, and achieve the goals for energy savings and peak demand reduction. Power system requirements must be met on a continuous basis, but they can be met in an optimized and economic manner. The DERMS is designed to react to localized constraints and knows exactly what steps to take to achieve an optimized state.

VVO provides the opportunity to optimize the system and result in reducing system losses, energy consumption and demand. The VVO system allows the system to operate at the voltage required at that given moment. Losses are minimized, peak demands are reduced, and the system is optimized which improves the overall life of the distribution assets.

5.1.2.7 Technology Innovation

Technology innovation is changing the manner in which electric utilities operate their systems. Constant and pervasive system monitoring and data gathering facilitated by Grid Intelligence is required to manage the high penetration of renewable resources and other DERs connected throughout the system. SCADA alone does not have the capability nor the intelligence to manage system constraints in an economical manner. Grid Intelligence technology is proven and will continue to be enhanced as new markets and use cases are developed in the industry.

Grid Intelligence in conjunction with the field area network supporting the communications from the field edge devices to the central system collects, analyzes and presents the data in an actionable manner designed to optimize the system based upon current operation conditions and predefined goals. Grid Intelligence allows advanced forecasting and control capabilities that would not be capable without this technology. Grid Intelligence allows the ability to share information with customers, improve access to markets, enable programs such as demand response and reduce peak demand on the system.

Many of the smart grid technologies require customers to install equipment or take action to achieve a benefit. VVO is an innovative technology that will allow utilities to save energy and greatly reduce costs without requiring customers to take any actions. Customers will receive the benefits without having to install equipment or change their usage patterns. VVO technology improves the Company’s ability to respond in real-time to match supply and demand by regulating voltage and power factor in response to real-time information.

5.1.2.8 Environmentally Friendly

An environmentally friendly grid is one that is optimized for interconnection and use of renewable resources while optimizing the system demand at all times of the year. Grid Intelligence provides the platform for the operator to minimize GHG emissions by integrating greater renewable energy DER and empowering customer energy options. This will allow the interconnection and operation of a larger percentage of renewable energy resources than otherwise could have been supported. Demand reduction programs supported by Grid Intelligence will lead to the replacement of inefficient end use devices.

VVO provides the opportunity for improved energy efficiency leading to decreases in demand and reduction in greenhouse gas emissions. In addition, the VVO system also enables the Company to manage customer power quality better and allows for a greater penetration of renewable DERs on the system and lead to a further reduction in GHG emissions.

5.1.3 SUMMARY

A modern distribution system is evolving at a rapid pace. Grid Intelligence technologies are foundational investments required for the safe, reliable and cost effective operation of the electric system. Utilities are experiencing extreme pressure to manage the large quantities of DERs coming onto the system in such a short timeframe. The ever increasing interconnection of intermittent resources resulting in two-way power flow is creating challenges for utilities who still are trying to operate the system manually. The intermittent nature of renewable resources are creating system challenges of voltage fluctuations and back flow. The implementation of Grid Intelligence technologies help utilities to address these challenges and continue to operate a safe, reliable, flexible, affordable and environmentally friendly electric systems.

The benefits of the Grid Intelligence investments are to provide greater monitoring, control and optimization of the distribution system and allow of an increased penetration of variable resources. Grid Intelligence quickly adapts to changing system conditions and rapidly recover from outages through an enhanced situational awareness. Grid

Intelligence is proven technology that supports the objectives for a modern electric system and the Company is in a position to maximize previous investments to improve the overall functionality of the system.

5.2 Advanced Metering Functionality

The information age has given us the ability to have data in the palm of our hands and when we want it. The satisfaction of having a world of information at our fingertips has changed the way we communicate, surf the web and shop. We have become accustomed to get news alerts as events are unfolding, up to date stock trading information, and accurate weather forecasts. The world is driven by data.

The modern electric system is also driven by data and information. Customers need data to inform their usage decisions. They need flexible pricing options that allow them to take advantage of their investments. Customers need to know how much electricity they are using and when that electricity is being used. Customers are willing to reduce their peak hour usage as long as they have the knowledge and tools to achieve the benefits. Timely and user-friendly data starts with a metering system that can accurately and automatically gather granular usage data, store the data in a meter data management system where it can be pushed to customers in a timely manner.

Advanced Metering Functionality (AMF) refers to the capabilities provided by the metering system. AMF provides the platform for the Company to measure and provide detailed and granular interval metering data of each individual customer. In some cases AMF provides data in real-time or near real-time and in some case the AMF provides data on a daily or monthly basis. AMF data provides the information necessary for demand management programs, time of use or time varying rates, and other customized programs focused on controlling or reducing energy consumption.

AMI allows the Company to continue to achieve savings in reduced staffing, more timely and accurate bills eliminates the need for additional truck rolls to read meters, virtual turn-ons and turn-offs reduces labor costs, fewer billing complaints allows disputes to be resolved faster, timely outage information reduces overall restoration time and tamper and theft related tools reduces the cost of lost revenue. These cost savings have been and continue to be shared with customers on an annual basis.

The Meter Data Management system collects, organizes and presents a vast and diverse set of metering data. Customer usage patterns can vary with the time of day, day of the week, and time of the year. Load can be influenced by weather or by the economy. Every customer is different and the granular data provided by interval metering is helpful for customer engagement efforts and developing products and programs to benefit the customer and the system by adjusting usage patterns. AMF can empower customers to take control of their own usage through bill alerts or individualized customer education.

5.2.1 DESCRIPTION

Technology innovation is driven by timely and accurate data. Legacy metering systems do not provide the level of granularity and timeliness required for the modern grid. AMF combines the metering systems and database required to measure, collect and present accurate and timely metering information in a manner that is useful to our customers and other stakeholders. The Company's advanced metering functionality vision consists of the following technology advancements: Advanced Metering Infrastructure, Interval Metering and a Meter Data Management System.

5.2.1.1 Advanced Metering Infrastructure (AMI)

Advanced Metering Infrastructure (AMI) is an integrated network of meters, communication systems and data management systems designed to measure and report on electric usage in an automated fashion. AMI has transformed the electric industry's ability to measure generation and load resources. AMI is an important foundational element to the Company's vision of an enabling platform. AMI provides data in a timely and detailed fashion and is able to be used by the Company and its customers to instruct and manage energy consumption.

The Company installed its first version of AMI over a decade ago. At that time, the Company had a decision to make: Should the Company move to the next generation of meter reading and install an automated meter reading (AMR) system or take a giant leap towards AMI while reducing operating costs, automating existing manual processes, improving data quality and providing the Company and its customers with data to support the advanced grid.

The difference between AMR and AMI is quite simple. AMR requires the meters to collect and store the data until the data is collected by a drive by meter technician. AMR is cost effective because it allows utilities to reduce meter reading staffing but it does not provide any further benefits. AMI on the other hand uses a communication system between the meters, the collectors and a head end database to transmit the data automatically. AMI provides the efficiency of reduced staffing, but it also provides benefits such as of outage reporting, time of use metering, tamper detection, and remote turn-on and turn-off just to name a few.

The Company implemented an automated metering infrastructure system that uses powerline carrier based technology. Powerline carrier uses the electric system primary conductors to communicate commands to the meters and transmits data from the meters back to the head-end system. This two-way communications technology is highly reliable and highly secure.

The Company's original AMI installation was state of the art when it was installed but has been outpaced by new technology that can provide more information in a more timely fashion. The Company recently completed an upgrade of the substation collectors that will allow interval meter readings to be transmitted once an interval meter has been installed. This will support the Company's plan for implementing time-of-use rates for various use cases.

5.2.1.2 Interval Metering

Interval metering is a granular record of energy consumption made in regular intervals throughout the day. Unlike the single monthly reading from days past, interval metering records how much energy was used and exactly when it was used. Energy conservation begins with accurate measurements and is invaluable information to educate customers on how to reduce their overall energy consumption. Interval metering enables the benefits of demand side management and ultimately a competitive distribution market.

Interval metering benefits the customer as well as the system. Consumers with interval metering and the ability and willingness to shift some usage to off peak hours not only benefits the customer through reduced rates, but it also benefits the system by reducing peak demand and deferring increases in capacity. Interval metering supports demand response programs and other energy management activities that rely on automation to reduce their electricity consumption at peak times.

Interval metering can also be used for matching renewable resources with an individual customer load profile to provide the largest benefits by using electricity when it is cheaper and reducing usage when electricity is more expensive. Price and consumption data are critical and time sensitive.

5.2.1.3 Meter Data Management System

Advanced metering functionality has drastically increased the amount of data that is received from each meter on the system. The volume, frequency, and resolution from interval metering, voltage monitoring, outage events, tamper detection and other system data has created the need for a system with the size and capability to manage the vast amount of data. A Meter Data Management System (MDM) processes and manages metering and meter operations data and facilitates the integration with other systems such as the customer information system, outage management system, GIS, and other customer facing systems.

MDM is the platform for sharing customer information in an accurate, timely and consistent manner. Application Data Interfaces are designed with the ability to transfer the data between software platforms for customers and other third parties to use the data for their benefit. MDMS is designed to improve customer service and response times for customer inquiries by providing the customer service representative an efficient tool get customer information on demand.

MDM is one of the tools that helps utilities to deliver demand response programs such as time-based rates and various load control solutions. MDM enables customers to learn about their energy use, possible rate programs, improves customer communications and increases overall customer satisfaction. MDM increase operational efficiency while improving customer satisfaction.

5.2.2 MAPPING TO OBJECTIVES

The Company has developed a set of objectives influenced by the United States Department of Energy, Massachusetts Department of Public Utilities and New Hampshire Public Utilities Commission. Examining guidance provided by these agencies reveals an emerging consensus around certain key areas of interest. The benefits and values achieved from the modern grid can result in cost savings for all users. This section identifies how the advanced metering functionality vision supports the objectives established by the Company.

Project/Functionality	Existing / Planned	Safety and Reliability	Customer Enablement	Security	Flexibility	Affordability	Demand and Asset Optimization	Technical Innovation	Environmentally Friendly
Advanced Metering Infrastructure (AMI)	Existing	X	X		X	X	X	X	X
Interval Metering	Existing		X		X	X	X	X	X
Meter Data Management System	Existing		X		X	X	X	X	X

Table 4: Advanced Metering Mapping

5.2.2.1 Safety and Reliability

The safety and reliability benefits provided by AMF benefit both the utility and its customers. AMF can be used to support the implementation of VVO that provides the opportunity to actively monitor and control load and power factor to reduce peak capacity during peak demand periods. AMF provide for improved outage management by providing improved outage detection, faster response time and reduced overall outage restoration. Integrating AMF data with the Company's outage management system, outages will be detected quicker, the location of the outage is identified faster and overall restoration will take less time.

5.2.2.2 Customer Enablement

Current pricing models support and inefficient use of the electric system. Rates are developed to recover the investment over all hours of the year even though all hours of the year are not identical. Using pricing structures that reflect the actual costs will drive more efficient use by customers. Variable pricing structures supported by AMF allows the Company to empower the customers with insight into their own usage. Incentivizing customers to use less energy at peak time gives the customer the ability to lower their overall bill while supporting the system. Efficient behaviors help to control rates for all customers.

AMF technology provides the Company with valuable insight into the customer's usage behaviors. Information reduces risk. AMF provides the opportunity to mitigate market and pricing risk for customers who are able to actively control their usages. Better understanding of how electricity is used within the house helps customers to better understand the size of their bill and increases confidence in the billing process overall. Customers who take the time to review and understand their electric usage will be rewarded with lower energy bills.

5.2.2.3 Flexibility

AMF is a foundational element that can be used for all different types of market based programs and opportunities for customers to reduce their overall expense. Rate design is currently limited by the metering information available from legacy metering systems. AMF provides information to allow flexibility in market and rate design to balance the benefits to the system and its customers.

Flexibility of information is key to the development of markets at the distribution level. AMF created opportunities for market providers to offer an array of choices for customers. An offering that works for a residential customer does not work for a commercial customer. Customers with installed DERs should be given the opportunity to maximize their investments.

5.2.2.4 Affordability

In the near future, the distribution system will see some major changes in the products and services it provides. Markets and pricing mechanisms will be in place for customers to receive payments or credits for allowing their equipment to participate or be controlled in certain programs aimed at optimizing the system. Advanced metering functionality provides the data necessary to support market activity.

Remote data collection from AMF replaces manual and error prone work practices with machine to machine data interchange. Data quality is improved, billing errors are minimized and data recording errors are eliminated. AMF is able to read meters in difficult to reach locations that often required multiple trips each month to obtain the reading. Improved meter reading accuracy reduces calls into the call center, the need to investigate and reissue customer bills that may have been printed in error.

5.2.2.5 Demand and Asset Optimization

Capacity constraints on the distribution and transmission systems drive system improvement projects (and thus capital investments), however metering and cost recovery is driven mostly by consumption measurements. Advanced metering functionality provides the data and tools for improving the process of managing customer usage and peak demand.

AMF and the rate structures supported by AMF promote reduction in demand by incentivizing customers to change their usage habits. Active management of peak demand usage reduces transmission and generation costs, defers costly system improvements and allows the system to operate in a more efficient manner. Lower capital expenditures resulting from reduced peak demand improves asset utilization and results in customer bill savings.

AMF and interval metering provides the Company with information to make more educated assumptions about future peak loads and allows the Company to size the system for the load it is serving. AMF is a foundational element of a successful demand management program.

5.2.2.6 Technology Innovation

Technology innovation is about disrupting the old days of doing business and is focused on data. Technology innovation is driven by information. AMF provides timely and accurate information that is used by many system, customer and market facing technologies. Timely and accurate data is key to the advanced grid. AMF supports important functions that are not possible with legacy metering infrastructure such as the ability to remotely measure electricity, connect and disconnect service, identify tampering, report outages, and monitor voltage. AMF also supports grid facing functions such as ADMS, system planning, VVO, and outage management. AMF supports customer facing technologies such as energy management systems, in-home displays, and programmable thermostats. AMF supports market facing functions such as time-based rate and demand response programs. AMF supports the further integration of renewable resources and other DERs designed to improve the efficiency of the distribution system.

5.2.2.7 Environmentally Friendly

The primary environmental benefits associated with AMF relate to the reduction of electricity usages and peak load reduction. The information provided by AMF gives customers the opportunity to take more control over their energy usage leading to reduced emissions. AMF supports reduced overall energy usage through VVO and energy management systems. AMF helps to reduce peak demand by supporting dynamic pricing (such as TOU or TVR), energy management and smart appliances. AMF reduce emissions by eliminating the transportation required for meter reading fleets.

Integrating DERs and other renewable resources into the distribution system is key to an environmentally friendly distribution system. AMF provides the information necessary to match actual load usage curves with the potential DERs supporting the load. In addition, AMF supports demand side management programs which reduces distribution and transmission peaks resulting in lower peak loads, reduces emissions and reduces the need for non-environmentally friendly generation resources.

5.2.3 SUMMARY

A modern distribution system requires data to enable innovative technology. Advanced metering functionality provides accurate, timely and granular data allowing customers the ability to learn about their electricity usage and the opportunities to take control and benefit from changing their usage patterns. The primary benefit to customers is a reduction in their bills for being flexible enough to modify usage during peak times. The primary benefit to the distribution system is a reduction in peak demand and deferral of capacity related distribution and transmission investments. The reduction in peak demand also produces environmental benefits by reducing emissions.

The Company's AMI system has been providing benefits to our customers for more than a decade. Recent technology upgrades to the system now support interval metering which supports the rate programs to support demand response programs and further integration of renewable resources. The Metering Data Management system provides the platform for sharing data with customers and interested third parties and will enable time-based rates. Interval metering will allow customers to manage their own risk and benefits. Advanced metering functionality is proven and a required component to develop the modern grid as an enabling platform.

5.3 Distributed Energy Resources

The growing penetration of variable loads and intermittent renewable resources creates a challenge for the electric system if the grid is not prepared to accept these resources. The Company's vision of the advanced grid is an enabling platform with the ability to interconnect a large quantity of renewable resources and other DERs.

DERs are electricity producing resources or controllable loads that are connected to the distribution system. The Company expects to see an increased interest in interconnections in our New Hampshire service territories in the near future and is implementing advanced monitoring and control technology solutions to enable this large amount of DERs and operate a safe and reliable system.

FG&E owns one utility scale solar installation located in Massachusetts. Solar Way is a 1.3MW solar facility provides enough electricity to serve an equivalent of over 800 residential homes. FG&E is using this installation as a pilot and continues to evaluate opportunities to install additional utility scale solar in areas of the system that may benefit from the additional capacity.

FG&E is currently installing a 2 MW/4MWh utility scale energy storage system at a substation in its Massachusetts service territory to defer the need for a costly substation expansion. The energy storage system has the ability to serve over 1,300 homes for over two hours. This energy storage system is designed to reduce peak loading on the substation equipment as well as provide voltage regulation and frequency regulation to the market. This is a significant size energy storage device equating to over 2% of the system peak for the Massachusetts service territory. FG&E is using this installation as a pilot and continues to evaluate opportunities to install additional utility scale energy storage in areas of the system that may benefit from the additional capacity.

Energy efficiency also plays a key role in an environmentally friendly grid. The energy efficiency ("EE") programs the Company offers to its customers are developed as part of a comprehensive, statewide approach to optimizing energy use by electricity and natural gas customers. These efforts aim to transform the marketplace for energy-using services and equipment in the built environment by working with distributors and retailers, building and installation contractors, and end use customers in the commercial, industrial, and residential sectors. The Company has pursued cost effective EE in pursuit of annual energy saving goals established through a robust stakeholder process. EE programs are informed by nearly two decades of experience working with stakeholders, consultants, our colleagues at the other gas and electric utilities, as well as our customers. Our internal EE staff of more than a dozen planners, implementers and administrators work across jurisdictions (i.e., in Massachusetts as well as New Hampshire) and is supported by a broad complement of vendors, contractors, builders and evaluation firms, all with in depth knowledge of demand side efficiency and conservation. By moving consumers and contractors away from less efficient products and appliances, our incentives continue to transform the market for lighting and equipment and train customers to consider not just up-front cost but lifecycle costs.

The Advanced Grid has the ability to plan for, monitor and control a diverse set of distributed assets on the system all designed to support the safe and reliable operation of the electric system. Advanced monitoring and control technology evaluates the system in real-time and issues control commands to optimize the system. An environmentally friendly grid is one that is optimized for interconnection and use of renewable resources while optimizing the system demand at all times of the year. The Advanced Grid needs to be flexible enough to integrate increased amounts of renewable energy and use these resources to optimize the system and minimize GHG emissions.

5.3.1 DESCRIPTION

The advanced grid will continue to experience a diverse set of users. Traditional users will continue to be consumers on the system. Prosumers who invest in technology will benefit from the investments they have made in technology. DERs are an important resource to a safe, reliable and sustainable electric system. Integrating renewable and intermittent resources is a challenge for the system that will be met with advanced monitoring and control technology. Non-traditional system improvements and system resources are integrated with a reliability, capacity and availability to be relied upon when planning and operating the system.

5.3.1.1 DER Interconnections

The modern electric system is changing at a rapid pace with the integration of distributed, variable and renewable resources combined and the focus on electrification of the transportation and heating sectors. New and different users are connecting to the system every day. The ever increasing levels of these resources will have a significant impact on the safe, reliable and cost effective operation of the distribution system.

Intermittent, renewable resources play an important role in the clean and sustainable operation of the electric system. Over the past several year, customer interest in rooftop solar installations has increased. These installations provide a benefit to the customers who install them as well as the electric system. Increased visibility and control deep into the distribution system is quickly becoming a necessity. System optimization and efficient use of the grid resources is increasingly more important in providing a safe, reliable, sustainable and cost effective electric system.

Advanced monitoring and control technologies relies upon a safe and reliable advanced communications system to provide communications for the monitoring and control of field devices. Advanced monitoring and control and control will allow an increased amount of DERs to connect to the system than would otherwise be interconnected.

DER interconnections create a challenge for the electric system to overcome. The electric system can experience reverse power flow at time of light load. The electric system has traditionally been designed for one-way power flow with the system protection settings and voltage regulation settings designed to protect the system under those conditions. Electric system designs continue to change to allow for the safe and reliable operation of the electric system under reverse power flow conditions. The Company continues to make system improvements to ensure the safety of the system and its customers.

UES and FG&E continue to experience a high penetration of DERs with over 3,000 interconnections across their service territories, primarily in Massachusetts. Across the Massachusetts and New Hampshire service territories, the penetration of generation is approaching 25% of peak load and approaching 80% of light load. The Company expects to see an increased interest in interconnections and changed its approach to forecasting and planning the electric system. The diversity and penetration of DER installations can have the impact of deferring investments in system capacity.

Hosting capacity analysis identifies portions of the system where DERs can be installed without the need for costly system improvements. The Company has an interactive mapping system designed for customers and developers to see if their potential project is located in an area where system improvements are likely to be needed or if their project can generally proceed without the need for a costly improvement. This empowers customers to make decisions on their investment in technology. The Company's goal is to continue to identify ways to increase the hosting capacity of the system.

Locational value analysis identifies the value that a DER would have to different parts of the system. Locational value analysis is a measure of much traditional system investment in capacity can be deferred through the installation of a DER. Reliability, capacity and availability are important factors to consider in locational value analysis.

The electric system is designed to be an enabling platform for DERs. Each installation is analyzed to ensure the safe and reliable operation of the electric system. A diverse set of distributed resources, when planned accordingly, can provide a benefit to electric system.

5.3.1.2 Utility Scale Solar

FG&E owns and operates a utility scale 1.3MW DC solar facility in its Massachusetts service territory. This ground mounted solar facility is installed on a repurposed brownfield site. The system is comprised of over 3,700 individual solar panels each capable of producing approximately 345 watts and is capable of producing approximately 1MW of AC power or the equivalent of over 800 residential homes. On average the system produces approximately 1,500 MWh of electricity each year. This is energy that is not purchased from the ISO-NE markets resulting in savings to customers.

FG&E uses monitoring infrastructure to conduct real-time oversight of the output and performance of the facility. This type of monitoring positions FG&E to better understand the effects of key factors (such as weather conditions, equipment performance, and operating parameters) and to appropriately address such factors.

Utility scale solar is an effective means for supporting a green and sustainable electric system. The Company continues to evaluate utility scale solar installations as non-wires alternatives to traditional system improvements. One challenge is the peak output of the solar facility which is in the early afternoon, does not match directly with the peak load times of the system which occurs in the early evening. Solar output is almost negligible at the time of the system peak between 6:00-7:00pm. Energy storage technology is needed to store the renewable power and use it at the time that would produce the greatest benefit to the system and its customers.

5.3.1.3 Energy Storage

FG&E is in the process of installing its first utility scale energy storage system in its Massachusetts service territory. The 2MW/4MWh battery-based system is designed to alleviate peak loading on a substation transformer to defer the need for a costly substation expansion and upgrade in capacity. The energy storage system connects directly to the substation and is sized to defer the need for the substation expansion to a timeframe outside of the 10 year planning window.

The energy storage system is designed to dispatch the battery in a manner that provides the most benefit to FG&E and its customers. At the time of system peak, the battery will be discharged to reduce loading on the substation transformer as well as lower the overall system peak which will reduce transmission capacity costs to our customers.

The energy storage system may also be entered into the ISO-NE frequency regulation and capacity markets. ISO-NE will have the ability to dispatch the capacity at the time it needs for frequency regulation as well as reducing our peak hour loading that is used to calculate our capacity charges. The energy storage system produces a revenue (savings) stream that will directly benefit our customers by reducing their bills without needed to take any action on their own.

The energy storage system is the first installed on a Unitil company’s system. The Company intends to learn from this non-wires alternative (NWA) project. The Company will learn from the operation of the system and confirm the benefits to the distribution system and its customers. Reliable operation of the energy storage system during the peak hours is important to the deferral of the substation expansion.

Energy storage technology will play an important role in the integration of intermittent renewable resources. Energy storage system provides the energy and capacity when intermittent resources such as solar or wind might be lacking. However, combining renewable generation with an energy storage system will improve the reliability, capacity and availability of the intermittent resources to a point where the system can rely on them when planning the system.

5.3.1.4 Smart Inverters

The installation of a DER with traditional inverters can lead to an increase in system voltage. The increase in system voltage can limit the amount of DERs which can be installed. Smart inverters are designed to help control the voltage. Controlling the voltage can allow an increase in the amount of DERs the system can safely interconnect.

Smart inverters have a robust software infrastructure, bidirectional communications capability and a digital architecture. Smart inverters need to be able to send and received information and commands. They need to monitor and react to system conditions or commands. Smart inverter technology continues to improve and become more cost effective. Many states are requiring smart inverters on new installations. States with renewable generation goals are implementing smart inverter rules to help meet the goals by improving the hosting capacity.

Utilities are required to maintain a certain bandwidth of system voltage. Providing customers voltage that is outside of the standard range can result in damaged equipment. Utility scale voltage regulation is one way to provide the voltage control required to increase hosting capacity. Smart inverter technology can eliminate the need for the distribution system improvements.

Smart inverters will play a large role in the monitoring and control of the electric system. Smart inverters in conjunction to advanced monitoring and control technologies from the utility will integrate to optimize the system and increase the hosting capacity to allow an increased amount of DERs on the system.

5.3.1.5 Electric Vehicles

Electric Vehicle (EV) adoption rates are reaching a tipping point where customer desire will rule over price point. The electric system must be planned to accommodate the additional load while providing incentives and rate mechanisms to encourage customers to charge their vehicles on off peak hours.

The load associated with charging a single electric vehicle roughly doubles the load of a residential house. On its own, it does not pose a problem to the electric system. Now consider two neighbors get EVs as well. Now the secondary conductors and service transformer feeding those houses could experience overloads. If several customers get EVs in a single neighborhood, the primary conductors feeding the neighborhood could too experience overloads. One can see how quickly the adoption rate could drive costly system improvements on the electric system.

The Company's approach to EVs is two-fold. First, effective EV charging rates incent customers to charge their EVs when it is most beneficial to the system during nighttime hours. Improving the load factor during off peak hours allows the system to operate in a more optimized manner. Second, the system needs to be planned in advance for the increase in EVs. System planning that includes the DER generation resources on the system in combination with the controllable loads on the system enable the utility to design and operate a safe and reliable system for all DER interconnections. Controllable loads such as EVs can be a benefit to the system at times of peak PV and low loads during the shoulder months of the year.

5.3.1.6 Demand Response

Demand response or active demand management strategy allows users of the system to actively support the reliable operation of the system while gaining a financial benefit. Over the past several years, the Company has been monitoring demand management demonstrations and programs taking place in other states to advance tailored methodologies for adoption in our service territories.

The goals of active demand offerings are to flatten peak loads, improve system load factors, and reduce costs for all customers. The most recent updates to the Company's energy efficiency plans include proposals for pilots to pursue active demand reductions. The approved pilot targeted C&I customers was expanded to residential customers with wireless thermostats interested in participating in the offering.

The Company implemented an active demand reduction offering, based on evaluated commercial and industrial active demand reduction efforts. The offering was designed to provide incentives to encourage customers to reduce demand at peak times. By reducing load during the ISO summer peak, the Company can reduce our share of the installed capacity cost allocation, thereby reducing costs for our customers.

The C&I load curtailment pilot was launched in April 2019 utilizing both the Company's existing staff along with support from a third party Curtailment Service Provider ("CSP"). The CSP worked with the Company to identify curtailable load, enroll customers, manage curtailment events and calculate performance and payments. The targeted dispatch load curtailment is operated on a technology agnostic pay-for-performance model in which participating customers are notified the day before the demand response event by 1:00 PM, giving them a chance to prepare to curtail operations.

One important objective of the initiative is to time curtailment events during the ISO-NE ICAP ("ICAP") hour. Because customers' kW usage on the ICAP hour determines the customers' capacity charges for the following year, aligning the event timing with the ICAP hour results in the greatest impact both to the customer and the electric grid. In order to increase the likelihood of achieving this alignment, several events are typically called over the course of the summer, but not so many that customers' are unnecessarily impacted.

Targeted active demand management, as a non-wires alternative to traditional system improvements, can also be used to defer specific distribution system investment. Under the right circumstances, customers may have the desire and the ability to offer to respond to load events by shedding load or increasing generation. The benefit to the system is the deferral of a costly system improvement while the customer can benefit from performing active demand management when the system requires it.

5.3.1.7 Energy Efficiency

The energy efficiency ("EE") programs the Company offers to its customers are developed as part of a comprehensive and collaborative approach to optimizing energy use by electricity and natural gas customers. These efforts aim to transform the marketplace for energy-using services and equipment in the built environment by working with distributors and retailers, building and installation contractors, and end use customers in the commercial, industrial, and residential sectors.

The Company works collaboratively with the state regulatory agencies and interested stakeholders to develop energy efficiency programs designed to meet state goals. The Company pursues cost effective EE in pursuit of annual energy saving goals established through a robust stakeholder process. The Company's energy efficiency programs are informed by nearly two decades of experience working with stakeholders, consultants, our colleagues at the other gas and electric utilities, as well as our customers.

The Company's existing portfolio of electric efficiency programs focuses on customers in three categories: non-low income residential customers, low income residential customers, and commercial and industrial customers. The primary electricity-saving residential offering provides discounted retail pricing to residential customers who purchase high efficiency lighting and electric appliances. The Company collaborates with retailers, distributors and the other electric utilities to ensure that high efficiency products are marketed to customers, and that point-of-sale discounts are provided to customers on high-efficiency promoted products.

By moving consumers and contractors away from less efficient products and appliances, our incentives continue to transform the market for lighting and equipment and train customers to consider not just up-front cost but lifecycle costs. For more substantial and expensive projects involving heat pumps or whole-home weatherization, the Company offers on-bill and third party financing options that allow customers to spread their share of the investment over a longer period of time and experience cash-flow positive savings. For income eligible customers, the Company pays 100% of the cost of energy improvements, eliminating one of the major barriers to participation for these customers.

In the commercial and industrial sector, the Company works closely with retailers and distributors to ensure that high efficiency lighting, motors and drives, HVAC, controls and other equipment are an accessible and attractive choice for contractors, builders and end use customers. By providing both technical assistance and cash incentives, our efficiency programs reduce the barrier that a higher up front cost presents to C&I customers, including municipalities and nonprofit organizations. As in the residential sector, on-bill financing programs allow qualifying commercial and industrial customers to offset some or all of the up-front cost of new or retrofitted equipment that is not covered by the program's cash incentive.

For both residential and commercial and industrial customers, the Company provides technical assistance, training and cash incentives to ensure that new buildings are built and equipped to high EE standards. This assistance is facilitated not only by the Company's key account managers, but supplemented by engineering and design-build firms that are familiar with both good building design and with our incentive programs.

In the residential programs, a fuel-blind approach to energy use results in significant heating fuel savings in programs focused on new construction and weatherization of existing homes. Just under half of the resulting energy savings comes from a reduction in electricity use from high efficiency HVAC, appliances and lighting.

For the commercial and industrial sector, the majority of savings come from custom projects among manufacturers, retail establishments, municipalities, and schools. While high efficiency lighting and controls continue to be the most important single contributor to overall EE savings, the Company is dedicated to reducing both energy use and demand by incenting high efficiency HVAC measures, motors and drives, appliances, plug loads, and process equipment. Technical assistance, professional referrals and financial assistance help customers to overcome non-cost barriers to the adoption of energy efficient equipment and operations.

5.3.2 MAPPING TO OBJECTIVES

The Company has developed a set of objectives influenced by the United States Department of Energy, Massachusetts Department of Public Utilities and New Hampshire Public Utilities Commission. Examining guidance provided by these agencies reveals an emerging consensus around certain key areas of interest. The benefits and values achieved from the modern grid can result in cost savings for all users. This section identifies how the distributed energy resources vision supports the objectives established by the Company.

Project/Functionality	**Existing / Planned**	**Safety and Reliability**	**Customer Enablement**	**Security**	**Flexibility**	**Affordability**	**Demand and Asset Optimization**	**Technical Innovation**	**Environmentally Friendly**
Generator Interconnections	Existing	X	X		X	X	X	X	X
Utility Scale Solar	Planned	X					X		X
Energy Storage	Planned	X	X		X	X	X	X	X
Smart Inverters	Planned	X	X		X	X	X	X	X

Electric Vehicles	Planned	X	X		X	X	X	X	X
Demand Response Program	Existing	X	X		X	X	X	X	X
Energy Efficiency	Existing	X	X		X	X	X	X	X

Table 5: Distributed Energy Resources Mapping

5.3.2.1 Safety and Reliability

Distributed energy resources is changing the manner in which power is generated and transmitted to the electric system. DERs can be used to pinpoint added capacity to specific locations on the electric system or can be aggregated to supply large amounts of power to the grid.

The growing penetration of variable loads and renewable intermittent distributed energy resources will create a challenge for the electric system. Capacity, reliability and availability are important considerations when evaluating non-wires alternatives to traditional system improvements. The ability to monitor and control a diverse set of distributed assets on the system will be critical to the safety and reliability of the system. Intermittent resources coupled with energy storage can provide a safe and reliable alternative to traditional system improvements.

Advanced monitoring and control provides the system operators the ability to safely and reliably respond to events that could pose a risk to the system or its customers. Advanced monitoring and control enables the managing loads and generation to control or prevent reverse power flow conditions and reduce the opportunity for protection issues related to ground overvoltage conditions.

Smart inverter technology provides added control and protection against overvoltage conditions often experienced with standard inverter technology.

5.3.2.2 Customer Enablement

Distributed energy resources are typically owned by customers and continue to gain popularity. An increasing number of customers desire to take more control of their energy usage. They desire more control over their electricity sources as well as how and when they consume the electricity. As the cost of technology continues to become more cost competitive, electric utilities are developing strategies to enable a seamless interaction with customer who deploy DER technology. The electric system as an enabling platform must be adept at managing the increasing quantity of DERs while also maintaining a reliable and stable network.

As more customers invest in DER, advanced monitoring and control becomes increasingly important for utilities. Enhanced interaction with customers enable the greatest benefit to the customer as well as the distribution system. Customer desire instant access to the most up to date information from their utility just like they are accustomed to having on the cell phones.

5.3.2.3 Flexibility

Designing and managing a flexible electric system is required for supporting the increase in penetration in DERs. The electric system as an enabling platform need to be flexible enough to safely and reliably operate a system with two-way power flows. The penetration of DERs such as distributed generation (i.e. rooftop solar), energy storage, and electric vehicles affect how the system is operated.

Increased DER is a double edged sword that needs to be considered. DERs can have the positive effect of reducing CO2 emissions with sustainable DG, providing capacity and reducing peak loading on electric lines, increasing self-consumption and providing customers with some independence from the electric grid. However, DER can be problematic for the electric system affecting stability and reliability due to the intermittent and unpredictable nature of DG, voltage fluctuations and two-way power flow.

DERs provide value to electric systems and flexibility. Energy storage systems and demand response supply the system with flexibility to safely and reliably increase the penetration of DER as well as shift the system peak resulting in less capacity and transmission congestion and lower generation requirements. Energy storage might provide the most flexibility because it can be used as a generation or a load source depending on what the electric system needs at the time.

5.3.2.4 Affordability

In the near future, the distribution system will see some major changes in the products and services it provides. Markets and pricing mechanisms will be in place for customers to receive payments or credits for allowing their equipment to participate or be controlled in certain programs.

Distributed energy resources allow customers to take more control of their energy use. It will take a combined effort of the customer and the utility to maximize the benefits to the customer and to the system. DERs can offset power system losses, transmission capacity charges, generation charges, and can defer costly capacity improvements by reducing system peak loads.

Demand response and energy efficiency programs provide an incentive to customers to use electricity more efficiently and to modify their usage patterns in a manner that reduces system loads. The distribution system must be operated in an optimized manner to gain the most value while also making it affordable. Optimization of DERs provides value to the customer, the Company and to the overall system.

5.3.2.5 Demand and Asset Optimization

DER penetration across the electric system continues to increase at an increased pace. DERs are electricity producing resources or controllable loads connected to a distribution system. DERs may include roof top solar, wind, CHP, energy storage, small gas powered backup generators, electric vehicles, and controllable loads. Behind the meter DER such as roof top solar is the largest application of DER technology across the service territory. System reliability and inefficient performance increase the risk profile for these DERs creating the need for optimizations.

An optimized electric system only uses what it needs at any given moment in time. An optimized system will react to changing system generation and load conditions in real-time and control the appropriate resources to ensure the safe and reliable operation of the electric system. DERs can offer great customer choice and also represent an opportunity to optimize overall system investments. Planning for the impact of DERs on the electric system requires visibility into the real-time operation of the DERs.

The DERMS in conjunction with the ADMS are key components to enabling a system that can be optimized for various different conditions such as voltage, load, losses, renewable generation, energy storage, and achieve the goals for energy savings and peak demand reduction. Power system requirements must be met on a continuous basis, but they can be met in an optimized and economic manner. The DERMS is designed to react to localized constraints and knows exactly what steps to take to achieve an optimized state.

5.3.2.6 Technology Innovation

Electric distribution systems are becoming more decentralized with the growth of DER penetration leading the way. Technology innovations in photovoltaics, energy storage, and energy management systems are driving the price point down and customer interest up. As technology continues to improve, the integration of DERs will continue to grow.

Customer expectations are changing where they are expecting their resources to be integrated into the grid to provide the most benefit to the customer and the system.

Utilities are quickly making adjustments to their electric systems to improve its ability to interconnect intermittent resources that are uncontrollable and unpredictable. Technology improvements are required to make the grid more flexible and the integration less complex. The Company is focusing its efforts on improved monitoring and control of the distribution system. This technology will begin to form the basis of distribution markets that allow peer to peer and group transactions, sophisticated pricing and a growth in electric vehicle adoption rates. Technology improves the ability to share information with customers, improve access to markets, enable programs such as demand response and reduce peak demand on the system.

Improvements to technology associated with DERs is endless. The sky is the limit. The Company's goal is to design and build an enabling platform that allows customers to connect with ease, the system to operate in a safe and reliable manner, and benefits are optimized for the customer and the system.

5.3.2.7 Environmentally Friendly

An environmentally friendly grid is one that is optimized for interconnection and use of DERs including renewable generation and controllable loads, while optimizing the system demand at all times of the year. The goal of cleaner and cheaper power has become synonymous with DERs. DERs provide clean energy and the opportunity to reduce CO2 emissions.

Technology improvements in roof top solar continues to drive the price point lower and lower. The costs of other DERs such as energy storage and energy efficiency improvements are also experiencing decreasing pricing and increased sales. Demand response opportunities continue to grow as home assets such as HVAC, water heaters, LED lights, thermostats and even electric vehicles as the ability to control these assets from the internet become more prevalent.

What does all of this mean? The ability to monitor and control DERs individually or in an aggregated manner will lead to more clean energy and demand reduction opportunities to offset centralized fossil fuel based generation and transmission capacity additions.

The electric system as an enabling platform strives to minimize GHG emissions by integrating greater renewable energy DER and empowering customer energy options. Technology advancements in monitoring and control of DERs will allow the interconnection and operation of a larger percentage of renewable energy resources than otherwise could have been supported. Demand reduction programs supported by advanced monitoring and control will lead to the replacement of inefficient end use devices.

5.3.3 SUMMARY

Utilities are experiencing extreme pressure to manage the large quantities of DERs coming onto the system in such a short timeframe. The ever increasing interconnection of intermittent resources resulting in two-way power flow is creating challenges for utilities who still are trying to operate the system manually. The intermittent nature of renewable resources are creating system challenges of voltage fluctuations and back flow. Advanced monitoring and control technologies are required for the safe, reliable and cost effective operation of the electric system. Technology for the utility and for the customer will allow these DERs to support the electric system.

The distribution system as an enabling platform must be operated in a safe and reliable manner, with the flexibility to interconnect large quantity of diverse DERs. Technology advancements in DERs is making the price more competitive and increasing adoption rates. DERs when planned properly will assist utilities in the pursuit of an optimized system;

one that is clean, affordable and enables customer to take an active role in their electricity usage. Reductions in customer usage, peak demand and system losses will result in further savings in generation and transmission costs.

5.4 Advanced System Planning

The growing penetration of variable loads and intermittent renewable resources creates a challenge for the electric system if the grid is not prepared to accept these resources. The Company's vision of the advanced grid is an enabling platform with the ability to interconnect a large quantity of renewable resources and other DERs. Advanced system planning forms the foundation for an enabling platform willing and ready to accept DERs and other electrification technologies.

Advanced system planning begins with an accurate system model. A GIS system that is maintained on a timely basis form the basis for the network model used in Advanced System Planning. A complete and detailed network connectivity models is essential and when used across multiple platforms allows for consistent results for real-time operation of the electric system.

Real-time system planning is foundational to the optimization of the electric system. The modern grid is constantly changing. Intermittent generation resources and added loads from electrification can drastically change operating conditions within moments. Real-time system planning enable grid operators the tools to make the necessary adjustments to optimize the system. Real-time system planning increases the safety, reliability and security of the electric system.

Forecasting is a critical component of advanced system planning. DER interconnections can be a challenge to the electric system if they are not appropriately integrated. DER forecasting enables the electric system to take advantage of DERs for the operation of the system. DER forecasting can identify the real cost of DERs in comparison to traditional alternatives and drive a lower cost and improved affordability across the system.

Electrification has the potential to double the electric loads on the electric system. Increased adoption rates of electric vehicles and heat pumps may have a negative effect on the electric system if the loads are not accurately forecast and included in system design and operation considerations.

DERs can provide can be a challenge and a benefit to the electric system. Advanced system planning reduces the risk associated with DER interconnections and enables the benefits to be realized by the system and customers. Hosting capacity and locational value analysis are tools that can be used to identify the optimal locations for DER interconnections maximizing the benefits to the customers and the system. Understanding the value and benefits of DERs will allow utilities to plan for and rely-on cost effective DER solutions to defer distribution system upgrades.

5.4.1 DESCRIPTION

Advanced system planning forms the foundation for an optimized distribution system that is safe, reliable, secure and affordable. Accurate system models that are accurate and up to date support consistent decision making. Real-time planning allows system operators to operate an optimized system, taking into account a diverse set of intermittent generation and controllable load resources. Forecasting of DERs and electrification technologies is critical to enable the increased adoption of these resources. Hosting capacity and locational value analysis provide the tools necessary to optimize the location of these resources.

5.4.1.1 Geographic Information System

A Geographic Information System (GIS) is no longer the simple mapping of utility assets. GIS is an enterprise relational database which provides an accurate representation of the electric network and is the foundation for all system planning and forecasting. GIS is designed to provide a spatial representation of the distribution system and the equipment connected to it.

The Company has been using various versions of GIS technology for over two decades. The electric system is a complex network of assets each with its own characteristics and settings. Electric systems are spread over hundreds of square miles and managing all of the data is complex. GIS is an effective tool used to simplify the management of these assets. GIS has revolutionized the manner in which the Company operates. GIS is used to collect, display, analyze and manage data. The spatial nature of the database allows the data to be shared or referenced in a visual representation encouraging creative solutions to otherwise complex maintenance or upgrade challenges.

The Company's GIS is an enterprise system and is integrated with many of the Company's other systems such as AMI, ADMS, OMS, CIS, mobile damage assessment and engineering circuit analysis software. The GIS system is also used on the natural gas side of the business and provides the basis for DIMP, TIMP, gas leak survey, and CMS.

GIS provides the basis for system planning activities for the Company. A complete and detailed network connectivity model is essential for planning the system. The GIS provides the detailed model of the electric system from the interconnection with the transmission system to the service transformers. Customers are mapped directly to the service transformer they are connected to. The GIS system also provides important engineering related information on specific equipment and construction types.

GIS provides the single network model to be used within the ADMS, DERMS, OMS and VVO systems. An accurate and consistent model used across all of these system will ensure consistent results for the real-time operation of the electric system. GIS provides the network model required for accurate real-time system planning.

5.4.1.2 Real-Time System Planning

Utilities have historically completed distribution level planning on an annual basis, primarily focused around the peak load hour in the summer and winter periods. This analysis is generally focused on one-way power flow in comparison to the limiting elements of a circuit. The static nature of this approach has supported the utilities for many decades. The legacy approach to system planning is quickly becoming inaccurate because the uses of the system are changing so rapidly.

The modern grid is changing at an accelerated pace. System planning must change as well. The modern grid must be designed and planned for two-way power flow, and increase in intermittent distributed energy resources and increasing loads connected to the system due to electrification. Utilities can no longer plan for the one-hour of the year. Real-time system planning is required to evaluate and optimize the electric system at all hours of the day.

The basis for real-time planning is an up to date and accurate system model. Advanced monitoring and control through the ADMS, DERMS, SCADA and VVO systems will provide the information required to plan and optimize the system in real-time. Real-time system planning will enable grid planners and operators to plan for and react to local disturbances before they cascade into larger problems.

Real-time system planning will allow operators the advanced monitoring tools to operate the grid in real-time, make the necessary adjustments to optimize the system and allows market based mechanisms that promote energy efficiency and reliability. Real-time system planning will increase the safety, reliability and security of the electric system.

5.4.1.3 DER Forecasting

DER can be one of the largest challenges to the electric system. Properly planning for DER interconnections can turn DERs into one of the largest benefits to the system. DERs are changing the make-up of the electric system at an alarming pace, allowing customers to take greater control of their electricity usage. DERs, when planned and forecasted accordingly, will potentially replace traditional grid improvements in infrastructure. If customer adoption of DERs outpace the utility's preparation and planning, new operational issues on the distribution system could result in costly upgrades.

The Company has already experienced a high adoption rate of rooftop solar installations in its Massachusetts service territory. The adoption rate will continue to grow into New Hampshire with improvements in technology that lead to a reduction in costs. Behind the meter energy storage has seen little activity in the Company's service territory to date, but become an important resource for the reliable interconnection and operation of intermittent resources. The drive for electrification will bring and increase adoption of electric vehicles and heat pumps.

DER forecasting is one tool that the Company will use to ensure the system is ready to interconnect DERs. In addition, day to day forecasting of DERs is important especially as the quantity and capacity of DERs are interconnected. More accurate inclusion of DERs into the Company's load forecast will provide a better understanding of the costs and benefits of the DERs. This will lead to more optimal investments such as non-wires alternative project to replace or augment the traditional distribution infrastructure.

Forecasting DERs is one of the first steps to advanced system planning. System planners and operators need to understand the amount, location and timing of DERs over an extended planning period. This is a difficult task which requires assumptions. Geospatial analysis supported by GIS is a critical component to the forecast. The old adage that all forecasts are wrong is true, but forecasts can be used in conjunction with sensitivity analysis to provide valuable information.

5.4.1.4 Electrification Forecasting

The goal of reducing emissions has become synonymous with electrification. Two of the largest opportunities for electrification receiving the most attention right now are transportation and building and industrial sectors.

Electrification of the transportation sector can include light-duty cars and trucks, medium-duty battery electric trucks, heavy-duty battery electric trucks, and battery electric busses. EV penetration is expected to have an impact on the Company's total system load forecasts however it is not anticipated that the Company's system design forecasts will increase by the amount of forecasted EV load in this document. Impact of EV load on the Company's system design forecasts will be incorporated into the electric system load forecasting process in the future.

The Edison Electric Institute's (EEI) national forecast for the number of EVs on the road is the basis for the Company's EV load projections. The EEI forecast along with New Hampshire Department of Motor Vehicle (NHDMV) and census data was used to project the number of EVs on the road and ultimately the number of EV chargers within the Company's service territories.

Department of Motor Vehicles (DMV) information on the number of EVs registered per New Hampshire County was used to estimate the current number of EVs in each of the Company's service territories. The estimated number of EVs in each of the Company's service territories was determined by calculating the number of EVs registered per adult and estimating the number of adults residing in each of the Company's service territories.

Once the estimated number of EVs in each of the Company's service territories was determined, the EEI national EV forecast was used to project the number of EVs in each of the Company's service territories for each year from 2020 through 2030. Three forecasts for each territory were created:

- High Rate – utilizes 100% of the EEI projection
- Moderate Rate – utilizes 75% of the EEI projection
- Low Rate – utilizes 50% of the EEI projection.

Utilizing the assumptions in the section below the estimated number of home level 1 and level 2 chargers in each service territory was calculated. EEI projections for the percentages of the total number of each type of level 2 charger allowed for the calculation of the estimated number of level 2 public and work place chargers.

Utilization percentages (percentage of total of each type of units charging) for each hour of the day for home, public (including DC fast chargers) and workplace chargers and the assumed demand for each type of charger was then used to calculate the forecasted load due to EV charging for each hour of the day. This methodology was repeated for each forecast type and each of the Company's service territories.

Electrification of the building and industrial sectors include air-source heat pumps, heat pump water heaters, electric machine drives, industrial heat pumps, electric boilers and electric process heating. This portion of the Company's electrification forecast is still being developed.

5.4.1.5 Hosting Capacity Analysis

Under the present tariff model, those wishing to interconnect onto electric distribution system submit an application with the applicable information and the location of the interconnection. The Company then evaluates each application to determine if any system improvements are required. This process works well, but without knowledge of the general capacity and limitations of specific areas, some applications are likely to be determined to be economically impractical. If these developers or DER owners had a greater visibility into the ability for the grid to accept DER, this should reduce some of the iterative analysis by the utility and developer trying to identify a good location. The overall goal is to improve the quality and practicality of the applications submitted for review.

Circuit capacity, sometimes referred to as "integrated capacity" or "DER hosting capacity," is challenging to define, because each circuit has its own characteristics and these characteristics change over time. The "hosting capacity" of a feeder is the amount of DER a feeder can support under its existing topology, configuration, and physical response characteristics without affecting power quality or reliability. Many considerations need to be evaluated depending on where the DER is located. The utility needs not only to look at the grid in the area of the interconnection (i.e. transformer and wire capacity, voltage control, etc.) but they also need to determine if this installation will have any effect on the overall loading on the circuit, substation or even back flow of power onto the subtransmission or transmission systems. This is a highly variable calculation depending on the situation on each individual circuit. There are many additional concerns that require analysis on a case-by-case basis for specific applications, but general loading information can be supplied at a substation or circuit level prior to receiving specific applications.

UES has been analyzing the ability and process of developing a DER Hosting Capacity for each circuit or substation. The analysis will quantify the capability of the system to integrate DER with the existing thermal ratings, protection and control system limits, and safety standards of the existing equipment.

UES has implemented an approach to evaluate the hosting capacity of each substation and circuit to determine how much DG could be added without the need for distribution system upgrades. This information is presented to the public as an interactive map allowing the ability to zoom to certain areas of the system to see if it would be a good location to site a DG or if the location may require some system improvements to support the interconnection of DG. This is a tool that the Company hopes the public will find useful.

5.4.1.6 Locational Value Analysis

Locational value analysis is used to determine the value a DER has to the distribution system and will service to improve the overall customer value proposition. Locational value analysis is a relatively new concept to DER interconnections but is an important consideration when trying to maximize the benefits of the DER to the system and its customers. The precise way to calculate locational value has not been developed yet, but the models continue to get more accurate over time.

Locational value analysis is difficult to calculate with a high degree of accuracy because conditions on the distribution system change very quickly based upon changes in load and other distributed resources. These changes can have a large impact on the value of a DER in a given location. Locational value analysis is still in its infancy. Locational value analysis is evolving as utilities understand more about the capacity, reliability, availability and life span of DER assets.

Developing the benefits for integrating DERs into the grid is a more complicated calculation than identifying the circuit capacity. The benefits include but might not be limited to the generation energy, generation capacity (distribution and transmission level capacity), reduction in losses, environmental, and other benefits. The circuit capacity study will help the Company and DG developers to better plan for DG growth. The benefits of DER Enablement ultimately depend on how much DER is installed.

Understanding locational value is essential for utilities to plan for and rely on cost-effective DER to defer distribution system upgrades. The hypothesis is that as the value of DER can be accurately calculated it will lead to more distribution system investment deferrals.

5.4.2 MAPPING TO OBJECTIVES

The Company has developed a set of objectives influenced by the United States Department of Energy, Massachusetts Department of Public Utilities and New Hampshire Public Utilities Commission. Examining guidance provided by these agencies reveals an emerging consensus around certain key areas of interest. The benefits and values achieved from the modern grid can result in cost savings for all users. This section identifies how advanced system planning and forecasting supports the objectives established by the Company.

Project/Functionality	**Existing / Planned**	**Safety and Reliability**	**Customer Enablement**	**Security**	**Flexibility**	**Affordability**	**Demand and Asset Optimization**	**Technical Innovation**	**Environmentally Friendly**
Geospatial Information System	Existing	X			X			X	
Real -Time System Planning	Planned	X	X	X	X	X	X	X	X
DER Forecasting	Existing	X	X		X	X	X	X	X
Electrification Forecasting (EV and Heat Pumps)	Existing	X	X		X	X	X	X	X

Hosting Capacity Analysis	Planned	X	X		X	X	X	X	X
Locational Value Analysis	Planned	X	X		X	X	X	X	X

Table 6: Advanced System Planning Mapping

5.4.2.1 Safety and Reliability

The safety and reliability of the electric system begins with accurate and detailed system planning. Accurate GIS modeling of the system provides the foundation for system planning. These models need to be accurate and timely in order to accurately depict existing field conditions. Inaccurate base models result in uninformed actions which could cause unintended consequences.

The increasing penetration of DERs causes significant changes on the distribution system on a minute by minute basis. Real-time system planning will be required to ensure the safe and reliable operation of the electric system. Increasing DER penetration and increasing loads from electrification activities place a higher importance on forecasting. Accurate forecasts are required to ensure the safe and reliable operation of the electric system.

Integration of DERs can impact the safety and reliability of the electric system if not interconnected in a planned and coordinated manner. Hosting capacity and locational value analysis when shared publicly can guide the installations of DERs to the locations on the system which provide the largest benefits. Cooperation between the utilities and the DER owners will ensure DERs are interconnected in a safe and reliable manner.

5.4.2.2 Customer Enablement

Advanced system planning forms the basis for customer enablement. Electric systems are dynamic with constantly changing loads and sources of generation. As more customers invest in DER, advanced system planning becomes increasingly important for utilities. Advanced system planning provides the insight into real-time system conditions and is enabling customers to use their resources in a manner to benefit the customer as well as the system. DER forecasting improves the Company's ability to prepare the system to interconnect more DERs than would otherwise be allowed. Electric vehicle and heat pump adoption rates continue to increase. The potential increase in load on the electric system is significant and if not planned appropriately will create problems for the electric system. Advanced system planning will ensure the system is designed to accept the additional load. Hosting capacity analysis will provide customers and developer to have information and data in advance of proposing a DER interconnection. Hosting capacity when coupled with locational value analysis will provide customers and developers to identify and calculate the benefit of interconnecting a DER in a certain location on the network. Advanced system planning provides the Company and its customers with the information required to enable customers to take control of their own implementation of technology.

5.4.2.3 Flexibility

Designing and managing a flexible electric system begins with advanced system planning. The electric system as an enabling platform needs to be flexible enough to safely and reliably operate a system with two-way power flows. The penetration of DERs such as distributed generation (i.e. rooftop solar), energy storage, heat pumps and electric vehicles affect how the system is operated. Advanced system planning allows electric system to be designed to balance supply and demand at all times. Advanced system planning provides the information necessary to address the variability and uncertainty of the diverse set of resources connected to the electric system. Advanced system planning provides the building blocks to ensure the future system possesses sufficient flexibility to accommodate the growth of DERs. Advanced system planning is required to ensure flexible generation, transmission, demand-side resources and system operations for a safe and reliable system. Flexibility comes with a cost, therefore advanced system planning is required to determine the amount and type of flexibility and the associated costs.

5.4.2.4 Affordability

Advanced system planning is required to assess the physical and operational needs of the system to enable safe, reliable and affordable service to customers. Changing customer expectations and integration of DERs must be planned in an integrated manner, involving stakeholder involvement and reviewing non-wire alternatives in addition to traditional investments. Forecasting of electrification and DER technologies allows the system to be designed to safely and reliably serve these customers. Hosting capacity and locational value analysis ensures that DER interconnections are providing the largest benefits to the customer as well as the system.

5.4.2.5 Security

The electric system will soon be influenced by market activities. Real-time system planning will ensure the system is designed with adequate resources to withstand sudden disturbances. The system is designed to remain intact even after outages and equipment failures. Real-time system planning can identify rapidly evolving threats and vulnerabilities with mitigation implemented in a timely fashion.

5.4.2.6 Demand and Asset Optimization

An optimized electric system only uses what it needs at any given moment in time. An optimized system will react to changing system generation and load conditions in real-time and control the appropriate resources to ensure the safe and reliable operation of the electric system. Accurate system models and advance system planning form the basis for optimizing the electric system.

DER penetration across the electric system continues to increase at an increased pace. DERs are electricity producing resources or controllable loads connected to a distribution system. DERs include roof top solar, wind, CHP, energy storage, small gas powered backup generators, electric vehicles, heat pumps and controllable loads. Behind the meter DER such as roof top solar is the largest application of DER technology across the service territory. System reliability and inefficient performance increase the risk profile for these DERs creating the need to optimizations. Hosting capacity and locational value analysis support the interconnection of DERs which provide an additional means of support for an optimized system.

5.4.2.7 Technology Innovation

Implementing innovative technology solutions require and an electric system that enables and encourages those technologies. As the industry transitions to the modern grid, advanced planning tools will be crucial to informing decisions regarding infrastructure and system changes. Fundamental changes to the electric system are required to integrate the new technologies in greater quantities. Advanced system planning allows utilities to make timely adjustments to their electric systems to improve its ability to interconnect intermittent resources that are uncontrollable and unpredictable. Technology improvements are required to make the grid more flexible and the integration less complex. The Company is focusing its efforts on advanced planning of the distribution system. Technology improves the ability to share information with customers, improve access to markets, enable programs such as demand response and reduce peak demand on the system.

5.4.2.8 Environmentally Friendly

An environmentally friendly grid is one that is optimized for interconnection and use of DERs including renewable generation and controllable loads, while optimizing the system demand at all times of the year. Advanced system planning forms the basis for optimization of the system. Advanced system planning models allow the operator to run scenarios at varying load and generation levels to find the optimal settings.

The goal of cleaner and cheaper power has become synonymous with DERs. DERs provide clean energy and the opportunity to reduce CO2 emissions. Hosting capacity and locational value analysis provides valuable information most beneficial locations for interconnecting DERs. Electrification activities such as greater adoption of electric vehicles and heat pumps will continue to reduce emissions.

5.4.3 SUMMARY

Advanced system planning provides a strong foundation for the evolving electric system. Accurate system models that can be used in real-time are a requirement for complete optimization of the system. The distribution system as an enabling platform must be operated in a safe and reliable manner, with the flexibility to interconnect large quantity of diverse DERs. Advanced system planning will support the further integration of DERs as well as electrification technologies such as electric vehicles and heat pumps. DERs when planned properly will assist utilities in the pursuit of an optimized system; one that is clean, affordable and enables customer to take an active role in their electricity usage. Reductions in customer usage, peak demand and system losses will result in further savings in generation and transmission costs.

5.5 Enhanced Customer Services

Customers of the modern grid have begun the transition from passive recipients to active participants in the energy markets. They will take an active role in technology deployment and control over their energy usage. Superior customer service is fundamental to the Company's Vision, Mission and Values. The Company's customer service offerings will continue to evolve with the needs of our customers. The transition from traditional customer service offerings to more personalized options is one of the important steps to fulfilling the utility customer of the future evolving expectations.

Enhanced customer services provide customers with a suite of tools and services to take control of their own electricity usage. The vision begins with providing digital options for common and existing services followed by enhancing and optimizing the communication channels between the Company and its customers. The vision continues with extending additional value to our customers with personalized products and services depending on the individual customer's desires. The overall vision is to provide a total energy solution that provides pricing and services personalized to allow customers to achieve the greatest benefits based upon the technology deployed by customers.

Customers desire the ability to take control of their own electricity usage and a comprehensive education and outreach plan provides an important foundation for our customers to not only understand these enhanced customer services but to also understand how they may benefit their energy lives. Education helps customers to understand the options available tailored to their individual usage patterns or technology deployment. A strong customer communication, education and outreach plan assists customers to understand the services available and which services provide the most benefits. Self-service, web based tools that are easy to understand and operate improves the overall customer experience.

Looking forward, we will continue to invest in technologies designed to support our commitment to strong customer experience. We recognize that the complete utility customer experience involves a comprehensive customer engagement strategy that includes system and technological opportunities, personalized assistance from customer engagement representatives, web and electronic communications, and personalized self-service options. We will continue to enhance our customer web portal, adding self-service options that enable customers to better manage their energy usage and accounts. Planned enhancements include a mobile app, artificial intelligence and chat features, together with a robust notification engine to proactively alert customers regarding payment activity, increases in usage, outage notifications, and the status of scheduled appointments.

Data sharing between the utility, customers and third parties may also be a solution to overcoming barriers that may exist for customer adoption. The Company continues to work with stakeholders on data sharing tools and standards (i.e. Green Button). Home energy management systems have become widely available, with lower costs over time. Data sharing standards and platforms should be considered that benefit the customer, the utility, society at large, and third party vendors. Partnerships with global vendors such as Amazon and Google may provide behind-the-meter services as a means to share data and enable customers to better understand and control their energy usage.

5.5.1 DESCRIPTION

UES's vision for enhanced customer services is segmented into four parts: Digitizing Core Services, Optimizing the Customer Lifecycle, Extending the Value-Add and Providing the Total Energy Solution. The vision includes a strong foundation of easy to use tools presented in a web-based platform that provides customers with access to digitized core services. Communication with the customer that engages the customer using the media channel they most desire is an important aspect to optimize the customer lifecycle. As our customer engagement continues to grow, the platform will extend added value to customers by providing more personalized options. The ultimate vision is to provide a total energy solution that meets the unique needs of all of our customers.

Figure 4: Enhanced Customer Services Roadmap

5.5.1.1 Digitizing Core Services

Enhanced customer services begins with improvements to the existing services provided to customers. Improved online options for billing and payments, outage communications, new connections, self-service transactions and general correspondence options. A web based platform is central to the Company's goal to assist with normal and emergency customer needs.

5.5.1.2 Optimizing the Customer Lifecycle

Communication with the customer is key to a strong customer experience. Every customer has a preferred method of receiving communication. Customer communications preference for outbound notifications ensures the customer receives information, alerts and insights from the Company using their media of choice. Optimized channel containment will keep customers engaged and provide customers the means to accomplish their task without the need of seeking the assistance of a customer service representative.

5.5.1.3 Extending the Value Add

Customers desire services that meet their individual needs. Extending the value-add provides the customer with personalized products and pricing that are not currently available. New pricing products provide the customers with the ability to maximize the benefit of their technology deployment. Partnerships with Behind the Meter vendors or energy related advice and consulting services provides the customer with recommendations on products and services that can empower them to take control over their energy usage. Energy contract management provides customers with a greater understanding of the contract details and how to best manage those contracts.

5.5.1.4 Total Energy Solution

Customers of the modern grid desire a one stop shop for all of their energy needs. Enhanced customer services provides the customer with a total energy solution. The platform will provide access to the transactional energy marketplace. Customers can obtain personalized rate plans, data products and services that meet their unique needs. Home energy management systems are available through partnerships between the Company and known vendor alliances. The total energy solution will be designed with the flexibility to meet changing customer needs into the future.

5.5.2 MAPPING TO OBJECTIVES

The Company has developed a set of objectives influenced by the United States Department of Energy, Massachusetts Department of Public Utilities and New Hampshire Public Utilities Commission. Examining guidance provided by these agencies reveals an emerging consensus around certain key areas of interest. The benefits and values achieved from the modern grid can result in cost savings for all users. This section identifies how the enhanced customer services vision supports the objectives established by the Company.

Project/Functionality	**Existing / Planned**	**Safety and Reliability**	**Customer Enablement**	**Security**	**Flexibility**	**Affordability**	**Demand and Asset Optimization**	**Technical Innovation**	**Environmentally Friendly**
Digitizing Core Services	Planned		X		X	X		X	
Optimizing the Customer Life Cycle	Planned		X		X	X		X	
Extending the Value-Add	Planned		X		X	X	X	X	X
Providing Total Energy Solution	Planned		X		X	X	X	X	X

Table 7: Enhanced Customer Services Mapping

5.5.2.1 Customer Enablement

Enhanced customer services requires a strong customer communication, education and outreach plan. Customer education is a critical aspect of increasing awareness and encourage adoption of new products and services. Easy to understand web-based tools provide customers with the opportunity to control their energy usage. Proactive alerts and preference-driven notifications provide customers with advance notification of changing circumstances.

5.5.2.2 Flexibility

Not all customers are equal. Each has its own individual value proposition when it comes to their electric usage. Some customers still prefer a passive approach as a load user while others have the means and desire to implement technology to become prosumers. Enhanced customer services provides the flexibility through personalized products and service offerings, individualized customer communications, customized energy related advice, and personalized billing and payment options that cover the wide range of users.

5.5.2.3 Affordability

The way customers use the distribution system is changing. Enhanced customer services will provide customers with personalized education and tools to enable customers to take control of their own energy usage. Personalized products and services designed to allow customers to maximize value and minimize cost helps to support a sustainable and affordable electric system. Enhanced customer communications, alerts and consulting advice educates the customer to make decisions that can reduce cost and increase the overall affordability of their service. Personalized rate plans and access to a transactional energy marketplace provide options to the customer to improve their overall value proposition.

5.5.2.4 Demand and Asset Optimization

Optimization of the electric system requires a combined effort of the Company and its customers. Personalized education, technology, products and services provide customers with the motivation to adjust their usage patterns to maximize the benefit to the system as well as reduce their costs. Active management of peak demand usage reduces transmission and generation costs, defers costly system improvements and allows the system to operate in a more efficient manner. Lower capital expenditures resulting from reduced peak demand improves asset utilization and results in customer bill savings.

5.5.2.5 Technology Innovation

Technology is moving at an alarming pace and is changing the operation of the distribution system. Customers have options that they never had before. The present challenge is that customers do not understand the opportunities available and how those opportunities can influence their individual situation. Enhanced customer services provides customers with the education to better understand the options. Online personalized customer communications and tools are provided to engage the customer in their electricity use and educate them on different options and plans that may better suit their desires. Data sharing products and services integrated with home energy management systems provide customers with the technology required to actively take control of their situation.

5.5.2.6 Environmentally Friendly

A sustainable and environmentally friendly electric distribution system requires effective and efficient use of electricity. Customers who have knowledge, tools and technology can support the overall goals of energy conservation during peak load hours leading to reduced emissions. Customers who are engaged and have a clear understanding of their individual situations have a greater tendency to make beneficial changes. The customer engagement platform will be a forward looking “one-stop-shop” for everything customers related to the products, services and rate offerings available to them.

5.5.3 SUMMARY

UES is a preferred energy partner with a portfolio of services which address the varying needs of customers where the Company competes for the customer relationship. Improving the awareness and visibility of these options supports the goal of delivering the right experience, products and services for each customer. Customers are no longer content as passive consumers. Advancements in technology, concerns over climate change and the desire to control costs while increasing functionality are motivating customers to increase their understanding of the options available. Enhanced customer services is designed to provide customers with the education, products, services and rate offerings available to maximize their individual value proposition.

5.6 Innovative Rate Design

Customers desire the ability to take control of their own electricity use. Customer have the ability to invest in technology to support their individual use cases. Customers desire a means to achieve a benefit from their investments that not only support their individual goals but also provide benefit to the electric system and other customers.

Historically, rate design has been a “one size fits most” approach. Demand based rates for large customers and volumetric rates for smaller customers. These rate designs have been in place for decades. Innovative rate design continues to review and evolve existing rate designs to enable customers to more efficiently manage their energy needs.

Given the various desires of our customers, needs of the electric system and dynamic nature of the markets, no single rate option will be suitable to serve the needs of all customers. Innovative rate design is a suite of rates tailored to different customer types and use cases. Innovative rate design affords customers the opportunity to adopt new technologies, manage energy consumption and actively participate in energy markets to enhance efficient utilization and consumption of electricity to save money.

The overarching objective of rate redesign is the development of pricing for grid services that adhere to the principles of fairness, transparency and economic efficiency. Transparent and economically efficient pricing structures will ensure a viable and sustainable long term model that provides sufficient revenue to support the modernization of the electric system. Innovative rate design encourages appropriate behaviors and assures fairness and equity among customers

The Company recognizes the evolving needs of the public that have occurred over the last several years and that are expected to continue in the future as customers transition from passive recipients to active participants in the energy market. The transition from offering traditional rate designs to tailored and more personalized options, especially for EV owners, is an important step to fulfill customers’ evolving requirements from their utility.

Customer education is an important aspect to innovative rate design. A strong customer communication, education and outreach plan is required to support new rate offerings. Customers will be more likely to adopt new rate structures if they are aware of and understand the new rates. An easy to understand rate comparison self-service tool (e.g. shadow billing) is a critical web based tool customers can use to compare different rate structures to their individual usage patterns.

5.6.1 DESCRIPTION

Innovative rate design is driven by timely and accurate data. the Company’s Advanced Metering Infrastructure, Meter Data Management system and Customer Information System provide the tools required to provide timely and accurate metering data for many different types of innovative rate designs and coupled with data sharing platforms, allow customers to make informed energy choices.

Innovative rates should be based on cost of service rate design principles to ensure economic efficiency and limit cost shifting. Critical peak pricing (CPP) and demand reduction approaches are also worthy of consideration in addition to tariff-based TOU rates.

Marginal energy costs are typically driven by wholesale electric market (ISO-NE in this case) factors and may not fluctuate for different customer segments. A utility's distribution-related costs are fixed in nature and are incurred to meet customers' non-coincident peak demands and do not necessarily exhibit time-varying cost characteristics. In most cases, demand charges for C&I customers better reflect the manner in which a utility's costs are incurred to serve such larger customers. Incremental loads may require new transformers, service lines and meter upgrades. Instances may also exist where the addition of loads would require an upstream feeder and/or substation upgrade.

UES believes that the rate design options for any type of electric load should be designed to promote the efficient use of the utility's electric system resources and reduce costs for all utility customers. Rate options must provide proper price signals and influence customer behavior in a manner that creates beneficial outcomes for the customer (through lower rates and electric bills) and for the utility (through a reduction in system costs over time). To achieve these objectives, the design of the rate options should only reflect system costs that are time-varying in nature, and provide customers a cost-based price signal through the rate design. The time-varying costs should drive the desired shape of the utility's system load curve and not simply represent a preconceived outcome based on non-cost or qualitative presumptions.

At the same time, it is also necessary to understand and evaluate how customers are responding to the utility's TOU rate options in order to make periodic refinements to the TOU rate design and identify how the utility's load shape and resulting costs will likely change over time. For example, some customers may find certain TOU rate design options to possess overly long peak time periods, precluding those customers from responding to the TOU rate in a meaningful way. In addition, some jurisdictions have designed TOU rates to create a significant peak to off-peak rate differential to increase the likelihood of a positive customer response without recognizing that the underlying costs of the utility are not accurately reflected by the rate design. In that case, a rate benefit is afforded to customers who can change their electric usage patterns even though the utility does not experience a corresponding reduction in cost. This may be deemed desirable for non-cost causative objectives, such as supporting technology adoption, gaining an understanding of consumer behavior, and insights into grid operations and future investment requirements by the utility. Notwithstanding the Company's earlier comments with regard to the non-time-varying cost characteristics of its distribution system today, incorporating considerations into the design of EV TOU rates that may be non-cost causative in the near term may provide an opportunity to gauge the resulting longer-term impact of EV adoption on the electric distribution system, as further discussed herein.

Innovative rate design considers the effect that technology adoption will have on the electric distribution system and subsequent system planning and investment. Technology adoption rates should be forecast over the coming years and integrate these loads into planning studies and load forecasts. Possible changes to engineering and construction standards may be warranted to ensure reliability, safety, and appropriate equipment sizing.

The design of electric services may need to change as well, such as shorter distances and increased conductor size to address voltage drop concerns. Ongoing capital budgeting may need to accommodate early replacement of current infrastructure that is undersized and unable to accommodate new customer loads. Additionally, the installation of interval metering should be considered for increasingly dynamic loads and generation that have the potential to export energy onto the distribution system and necessitate more granular planning analyses.

Innovative rate design may also include make-ready programs, charging incentives, and behind the meter partnerships with third parties. Data sharing between the utility, customers and third parties may also be a solution to overcoming barriers that may exist for customer adoption. The Company continues to work with stakeholders on data sharing tools and standards (i.e. Green Button). Home energy management systems have become widely available, with lower costs over time. Data sharing standards and platforms should be considered that benefit the customer, the utility, society at large, and third party vendors. Partnerships with global vendors such as Amazon and Google may provide behind-the-meter services as a means to share data and enable customers to better understand and control their energy usage.

5.6.2 MAPPING TO OBJECTIVES

The Company has developed a set of objectives influenced by the United States Department of Energy, Massachusetts Department of Public Utilities and New Hampshire Public Utilities Commission. Examining guidance provided by these agencies reveals an emerging consensus around certain key areas of interest. The benefits and values achieved from the modern grid can result in cost savings for all users. This section identifies how the innovative rate design vision supports the objectives established by the Company.

Project/Functionality	**Existing / Planned**	**Safety and Reliability**	**Customer Enablement**	**Security**	**Flexibility**	**Affordability**	**Demand and Asset Optimization**	**Technical Innovation**	**Environmentally Friendly**
Residential/Business TOU	Planned	X	X			X	X	X	X
EV TOU	Planned	X	X			X	X	X	X
Distributed Energy Resources	Planned	X	X			X	X	X	X
Behind the Meter Partnerships	Planned	X	X			X	X	X	X
Make Ready Programs	Planned	X	X			X	X	X	X

Table 8: Innovative Rate Design Mapping

5.6.2.1 Safety and Reliability

Rate design and technology innovations must go hand in hand. Improper rate design can create unintended consequences. Safety and reliability of the electric system must have a high priority in rate design in order to design a rate mechanism that is sustainable and supportive of the needs of the electric system. Rate design should encourage and incentivize customers to shift their usage away from the peak periods and shift generation away from light load periods. Reducing loads at peak and reducing generation at light load times will reduce costs and improve the reliability of the electric system.

5.6.2.2 Customer Enablement

A successful implementation of innovative rate designs requires a strong customer communication, education and outreach plan. Customer education is a critical aspect of increasing awareness and encourage adoption of innovative rate designs. An easy to understand rate comparison tool (i.e. shadow billing) is a tool customers can use to compare their historical usages against different rate designs. This tool allows customers to understand how they can change their usage behaviors to maximize their benefit. Customers who feel empowered are more likely to participate in different rate design opportunities.

5.6.2.3 Affordability

In the near future, the distribution system will see some major changes in the products and services it provides. Markets and pricing mechanisms will be in place for customers to receive payments or credits for allowing their equipment to participate or be controlled in certain programs aimed at optimizing the system. Innovative rate design provides the means for customers to receive benefits for taking control of their usage. Customers will have the ability to choose the rate designs that produce the most value for their situation. Innovative rates are designed to reduce the overall cost of the electric system and promote usage during off peak timeframes.

5.6.2.4 Demand and Asset Optimization

A primary goal of innovative rate design is to encourage customers to shift load away from peak load times and to shift generation away from light load periods. Capacity constraints on the distribution and transmission systems drive system improvement projects. Innovative rate design can encourage and incentivize customers to manage their usage and peak demand. Active management of peak demand usage reduces transmission and generation costs, defers costly system improvements and allows the system to operate in a more efficient manner. Lower capital expenditures resulting from reduced peak demand improves asset utilization and results in customer bill savings.

5.6.2.5 Technology Innovation

In the advanced grid, Customers benefit from their investments in technology. Customers will have tools in place to evaluate their investments prior to making them. Innovative rate design enables customers to take control of their electric consumption and when it occurs. Customers should have a mechanism in place to receive value from benefits that can be monetized. Current pricing models support and inefficient use of the electric system. Rates are developed to recover the investment over all hours of the year even though all hours of the year are not identical. Using pricing structures that reflect the actual costs will drive more efficient use by customers.

5.6.2.6 Environmentally Friendly

The primary environmental benefits associated with innovative rate design relate to the reduction of electricity usage and peak load reduction. Innovative rate design provides customers the opportunity to take more control over their energy usage leading to reduced emissions. Energy efficiency activities are effective at reducing electricity consumption, but that only goes so far. Effective rate designs supporting dynamic pricing (such as TOU or TVR), energy management and smart appliances can have an even greater impact at reducing system peak demand.

Innovative rate designs that further integrate DERs and other renewable resources into the distribution system is key to an environmentally friendly distribution system. Well-designed rate programs which reduce distribution and transmission peaks resulting in lower peak loads, reduces emissions and reduces the need for non-environmentally friendly generation resources.

5.6.3 SUMMARY

The electric system is changing and customers desire to use the system in different ways. Technology innovations are providing customers with cost effective means to take control of their electricity usage. A suite of innovative rates tailored to different customer types and use cases provide benefits to customers as well as the distribution system. The transition from traditional rate offerings to more personalized options is an important step towards meeting customer desires as they transition from passive recipients to active participants in the energy market.

Innovative rates are designed to be fair, transparent and economic. Unintended consequences affecting the safety and reliability of the electric system can be avoided while encouraging appropriate behaviors and assuring fairness and equity among customers. Data sharing can provide customers with the information they need to make decisions regarding their energy consumption. Customer outreach and education improves the overall understanding and encourage adoption of new rates. Innovative rates will evolve with customers' needs, expectation and use. Innovative rate design is a required component to develop the modern grid as an enabling platform.

6 PROJECT PLAN

This section of the report details the project plan that consists of foundational elements to the Company's Advancing the Grid vision. The projects presented here are required to facilitate the distribution system as an enabling platform. This plan is designed to be flexible to changes in technology, system needs and customer desires. These projects will provide the foundation to enable future investments.

6.1 Grid Intelligence

Grid Intelligence technologies rely upon a safe and reliable advanced communications system to provide communications for the monitoring and control of field devices. The Company's Grid Intelligence vision consists of centralized software systems and the installation of field devices and a field area network for ADMS, DERMS, VVO, SCADA, mobile damage assessment, further integration of AMI and OMS systems and distribution automation.

6.1.1 Field Area Network

The Company currently uses a powerline carrier AMI system, and a combination of wireless (cellular) and land-line telecommunications services for the existing SCADA communications. The Company does not have a FAN installed in New Hampshire that is capable of supporting the capability and functionality required to support the functionalities identified as part of the plan.

This project consists of installing a FAN including communications between collectors and endpoint devices (meters and distribution devices) and backhaul communications from collectors at each substation to the central office. The Company expects that the deployment of a FAN will follow the same prioritization plan for substation and circuit deployment.

6.1.1.1 Description

This project consists of installing a FAN, including communications for field based endpoint devices and adequate backhaul communications. In the context of the modern grid, communications is the enabling system that makes it possible for all parties to interact and share information. The FAN will handle data traffic between distribution and grid edge devices and centralized information and operational systems. The FAN can be used by most of the modern grid systems that the Company implements. These may include SCADA controlled devices, Volt/VAr Optimization devices, advanced metering, distribution automation and DER management.

As part of its grid modernization plan in Massachusetts, a specification was developed and completed to request proposals (RFP) from vendors for field area network consulting services. The vendor was selected for the consulting services to assist in the specification and evaluation of proposals for a FAN throughout its electric service franchise area in Massachusetts. The following tasks were completed through the assistance of this consultant: identified the needs and requirements of the FAN, developed a specification for the network, created a list of appropriate bidders, issued an RFP to the list of bidders and completed a review and evaluation of different approaches to implementing a FAN.

The Company evaluated several options of building a radio frequency (RF) communications network in addition to partnering with an existing carrier s. Based upon the bidding evaluation, the Company decided on the carrier solution for our field communications.

Unitil Corporation will utilize the AT&T FirstNet network in New Hampshire and Massachusetts. AT&T FirstNet is a nationwide high-speed wireless network reserved for use by public safety and emergency first responders. It is designed to allow essential workers and emergency first responders the ability to communicate across a network that is separate from the communication paths used by the general public. This network also comes with a higher service level agreement that gives it priority if repairs are required. For applications where reliability and redundancy is critical, the Company has an existing contract with another carrier vendor for private area network services and would install redundant communications at these locations.

6.1.1.2 Benefits:

A FAN is an enabling technology that would provide the Company with the communications backbone to install many of the grid modernization initiatives being considered. The installation of a FAN without any of the other programs does not result in any monetizable benefits. However, the VVO system cannot provide the benefits identified without a FAN.

6.1.1.3 Project Timeline and Cost Estimate:

The FAN project is closely aligned with the ADMS, SCADA and VVO projects. The schedule for the FAN is based upon the prioritized listing of circuits and substation from the VVO project.

Year	1	2	3	4	5	6	7	8	9	10	Totals
Benefits (000s)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
Capital Costs (000s)	$90	$56	$127	$626	$325	$463	$780	$811	$640	$704	**$4,622**
O&M Costs	$0	$0	$4	$23	$32	$47	$71	$94	$106	$124	**$500**

(000s)											
Total Costs (000s)	**$90**	**$56**	**$131**	**$649**	**$357**	**$510**	**$850**	**$906**	**$746**	**$828**	**$5,122**

Table 9: FAN Benefits and Costs

FANs have gained a considerable amount of interest from utilities and regulators who are interested in modernizing their electric systems. A FAN is the communications network between the field end devices such as meters, reclosers, regulators, fault sensors, and any other intelligent end devices capable of gathering and recording information. The FAN takes that information and transmits the data back to the head end system such as and ADMS, OMS, Meter Data Management (MDM) or other database. These head end systems use real-time data to make application decisions, for optimization of voltage for example, and send the appropriate control signals back to specific devises on the distribution grid to achieve that optimization.

In the context of the modern grid, communications is a foundational technology that makes it possible for systems, operators and stakeholders to interact and share information. The FAN will handle data traffic between distribution, grid edge devices, centralized information and operational systems. The FAN will be used by most of the modern grid systems to be implemented.

There are many different technology options for a FAN such as wireless mesh, point-to-point fiber, point-to-point POTS line, radio, and microwave, just to name a few.

The Company has determined through a competitive bidding process conducted by FG&E that a carrier based wireless network makes the most sense for the applications being considered. The Company also has the option of installing redundant, multivendor, wireless communications at critical sites to provide redundancy and reliability. This carrier-based network approach should provide a cost effective, scalable and flexible communications system capable of transferring the amount of data for all of the programs that the Company is considering in its grid modernization plan such as AMF, expanded SCADA, VVO, and the communications needed to operate an ADMS.

The implementation of a FAN is an enabling technology that would provide the Company with the communications backbone to install many of the grid modernization initiatives being considered. The installation of a FAN without any of the other programs does not result in any monetizable benefits.

6.1.2 Advanced Distribution Management System (and DERMS)

UES manages its distribution system without much control or visibility past the distribution substations and does not have real-time visibility into the vast majority of the distribution resources connected to the network. Limited tools are available to monitor and control the influx of intermittent renewable resources which can cause two-way power flow concerns. These resources have a substantial impact on reliable operation of the system. This mode of operation is not sustainable in the future.

An ADMS system can provide many different functions such as (but not limited to) self-healing automation, control for distributed energy resources, additional SCADA functions across the distribution system, real-time load flow and circuit analysis, demand response, outage restoration, direct load control, network configuration, and integration of outside data sources such as real-time weather and VVO. The ADMS will provide the visibility and control required to operate the advanced grid in a safe and reliable manner. The ADMS will also provide valuable information during outage events and enhance situational awareness resulting in shorter outage durations.

The Company ADMS system will be implemented with the following functionalities:

- GIS editor to transfer the network model from the GIS to the ADMS on a routine basis as changes to the network topology are made in GIS
- Verification of network connectivity
- Enhancements of existing OMS and SCADA systems
- Switching manager and simulation module
- Volt/VAr Optimization
- Crew assignments
- Engineering based load flow and circuit analysis tools
- Hardware, software, and training

An ADMS system will need to closely integrate with other enterprise systems to realize its full potential such as the FAN to provide communication to field devices, the installation of field devices that have the ability to be controlled and a DERMS which provides the monitoring and control of DERs connected to the system.

This complex project will take several years to implement, but it will serve as one of the foundational pieces to achieving the objectives described below.

6.1.2.1 <u>Description</u>

The Company's Massachusetts affiliate is in the process of implementing an Advanced Distribution Management System (ADMS) throughout its electric service territory in Massachusetts. Given the nature of the systems and its integration with other systems, UES will implement ADMS for its New Hampshire service territories as well.

An ADMS is the next step in the evolution of distribution management systems. An ADMS integrates a comprehensive set of monitoring, analysis, control, planning, and informational tools that work together with one common network model. An ADMS merges existing OMS, ADMS, unbalanced loadflow, short circuit analysis and SCADA systems together to provide a real-time view of the distribution system.

An ADMS system can provide many different functions such as (but not limited to) self-healing automation, control for distributed energy resources, additional SCADA functions across the distribution system, real-time load flow and circuit analysis, demand response, outage restoration, direct load control and network configuration. Additionally the Company's ADMS will utilize "real-time" unbalanced load flow calculation results to automatically control distribution equipment for VVO.

The plan for ADMS includes the implementation of a DERMS in the future. This is an add-on to the ADMS which provides the ability to manage and control multiple DER facilities and other infrastructure (electric vehicle charging stations, demand response, etc.) including both company owned and customer owned facilities. DERMS will provide the information and control necessary to effectively manage the technical challenges posed by a more complex grid. The DERMS system provides the utility the ability manage the impact of DER and operate the system more efficiently. Appendix B, which is the ADMS Project Description submitted in connection with the FG&E Grid Modernization Plan, describes the functionality in more detail.

6.1.2.2 Benefits:

ADMS is an enabling technology. The ADMS will enable effective VVO, reducing customer energy consumption by 2-4% and commensurate peak demand reductions. The benefits will accrue directly to consumers as reductions in electricity bills, and through utilities as reductions in demand charges. The ADMS will also enable better voltage control for integration of DER and improved reliability through FLISR. The ADMS will serve as a platform for more advanced modules such as a DERMS. DERMS will provide the visibility and control to enable an increased quantity of distributed resources. Quantifiable benefits are shown under the other projects.

6.1.2.3 Project Timeline and Cost Estimate:

Implementation has begun. The base software and network environment is in production. Project costs demonstrated here include GIS data model improvements to include the necessary data required for ADMS, DERMS module purchase and integration, model build within ADMS and mapping development for loading analysis, reliability analysis, hosting capacity, and heat map.

Year	1	2	3	4	5	6	7	8	9	10	Totals
Benefits (000s)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
Capital Costs (000s)	$350	$668	$468	$378	$298	$170	$0	$0	$0	$0	**$2,331**
O&M Costs (000s)	$44	$46	$47	$48	$50	$51	$53	$55	$56	$58	**$508**
Total Costs (000s)	**$394**	**$714**	**$515**	**$426**	**$347**	**$221**	**$53**	**$55**	**$56**	**$58**	**$2,839**

Table 10: ADMS Benefits and Costs

A modern distribution system is evolving at a rapid pace. The ever increasing interconnection of intermittent resources resulting in two-way power flow is creating challenges for utilities who still are trying to operate the system manually. The ADMS will allow the electric system to increase renewable integration and enable more customer energy options at the same time providing safe and reliable service at a reasonable cost. The benefits of the ADMS and DERMS are to provide greater monitoring, control and optimization of the distribution system and allow for an increased penetration of variable resources. The ADMS will quickly adapt to changing system conditions and rapidly recover from outages through an enhanced situational awareness. The ADMS meet all of the objectives for a modern electric system and the Company is in a position to maximize previous investments to improve the overall functionality of the system.

6.1.3 Volt/Var Optimization

VVO is a proven technology for utilities to save energy for customers and reduce system demand all while ensuring reliable service. VVO provides benefits to customers without customer investment in technology or management of their loads. VVO also helps to integrate DERs, by controlling the voltage variations caused by DERs. The VVO project will deliver significant and measurable benefits for the Company and its customers, while creating platform capability to be leveraged in the future.

6.1.3.1 Description

The scope of the project includes installing automated controls on all voltage and reactive power equipment on select distribution circuits. This includes controls of all capacitor banks, voltage regulators and transformer load tap changers (LTCs). In some cases the equipment in the field is of the age that a simple addition of a control is not feasible and the entire voltage regulator or capacitor bank requires replacement. In addition, line sensors to measure voltage and energy will be installed at strategic locations on the circuits. The operation of these control devices will be coordinated and optimized by the ADMS. The communication between the ADMS and the VVO controls will be designed and installed as part of the FAN project. The design requirements of the VVO system will be coordinated with the plans of the ADMS, SCADA and FAN projects.

There are three primary aspects to implementing a VVO program: communications, software intelligence, and field equipment. A robust communications network is the foundation for a successful VVO program. The communications network described earlier in this report will be designed to support the VVO program. The software intelligence will be discussed as part of the ADMS project.

Voltage regulation refers to the management of circuit level voltage in response to the varying load conditions. There are two primary devices required to control the voltage on a distribution circuit: transformer LTCs and voltage regulators. The distribution management system uses input from voltage sensors across the system to adjust the voltage regulators and LTCs to provide power within an appropriate voltage limit. Capacitors are used for reactive power (VAr) regulation.

Although the project does not presently include plans to control customer owned inverters, the Company plans to implement a system with the possibility of controlling inverters along with capacitors, to provide reactive power to the distribution system.

UES has hosted many working meetings and demonstrations with various vendors to understand the different ways to implement a VVO system. The Company has evaluated two basic approaches to implementing a VVO system: model based and measurement based) and decided that a model based system would be implemented through integration with ADMS.

In a model based system, the system utilizes a dynamic operating model of the system in conjunction with real-time information from the field and runs this information through a complex optimization algorithm, within an ADMS, to optimize the performance of the distribution system. The system model and algorithm combined with remote field measurements and control enable the circuit to be optimized based upon minimizing power loss or demand while maintaining a tighter acceptable voltage profiles on each distribution circuit. The benefit to this approach is that fewer field devices are required since the algorithm relies heavily on the model.

6.1.3.2 Benefits:

The VVO system operates by constantly optimizing voltage regulation (voltage regulators, LTCs) and reactive compensation (through switched capacitor banks). The VVO project is expected to reduce customer energy consumption by 2% and is expected to reduce system and circuit peak demand by a similar amount. This will directly benefit customers by reducing their electricity consumption and thereby reducing their bills.

6.1.3.3 Project Timeline and Cost Estimate:

UES has learned that the implementation of the VVO, FAN, SCADA and ADMS projects are closely tied together. The Company's plan is to implement these projects on a substation by substation basis. For instance, the FAN, VVO, SCADA and ADMS projects would be implemented at the same time or in close time frame to each other. In order to facilitate this effort, the Company developed a ranking system to prioritize which substations provide the largest benefits to customers and should be completed first.

UES developed a prioritization model comparing the cost of implementation versus the number of customers affected and well as the cost versus the peak demand (kVA). Each measurement was weighted 50% and the resulting combinations were ranked to provide the largest benefit/cost ratio. Other aspects (such as planned circuit ties, and coordination of other work planned at the substation) were then analyzed to create the schedule of implementation.

The Company's prioritized ranking system weighs the ability to reduce peak demand evenly with the opportunity to save the largest number of customers on cost of energy consumption. Secondly, engineering judgement was used to group the circuits that are planned to tie with each to provide back-up restoration. In this manner, VVO could be implemented even when the system is not in its normal configuration, but in a planned restoration configuration.

In the ranking procedure, each location was ranked by $/kVA and separately ranked by $/customer. The ranks were then summed together to establish the overall ranking. The rank with a lowest number provides the largest benefit/ cost. The substation transformer or circuit with this lowest score becomes the highest priority for implementing the projects. After all locations were ranked and charted, a cut-off point was determined where there was a noticeable gap of cost and benefit. Therefore it was decided not to implement VVO in locations that did not provide adequate benefit compared to the cost of implementation.

The table below provides the results of the calculations. The substations have been ordered from highest to lowest priority.

Substation Transformer / Circuit	Number of Customers	Cost/Customer ($)	Peak Demand (kVA)	Cost/kVA ($)	Calculated Rank	Adjusted Rank
Capital - Gulf Street - 4.16 kV	769	127.13	1,695	57.68	1	1
Capital - Gulf Street - 13.8 kV	1,049	508.91	6,073	87.90	9	2
Seacoast - Winnacunnet Road Tap	874	154.90	1,698	79.73	3	3
Seacoast - Gilman Lane	4,246	257.93	18,942	57.82	2	4
Seacoast - Portsmouth Ave	1,710	614.44	9,992	105.15	19	5
Seacoast - Willow Road Tap	1,834	593.28	6,280	173.26	27	6
Capital - Bow Junction - 13.8 kV	2,092	313.49	8,622	76.06	4	7
Seacoast - Hampton Beach	3,258	237.75	8,067	96.02	5	8
Seacoast - High Street	2,659	448.88	6,380	187.08	21	9
Capital - Penacook - 13.8 kV	3,741	192.34	5,872	122.54	8	10
Capital - Penacook - 34.5 kV	1,955	408.40	6,220	128.36	13	11
Capital - West Portsmouth - 13.8 kV	1,299	268.56	3,531	98.80	7	12
Capital - West Portsmouth - 4.16 kV	16	2459.51	509	77.31	18	13
Capital - Iron Works Road	2,160	431.22	8,572	108.66	10	14
Seacoast - Guinea Road Tap	1,651	299.14	5,000	98.78	6	15
Seacoast - Winnicutt Road Tap	1,952	610.78	5,159	231.10	31	16
Capital - 37X1 - 37X1	183	303.22	374	148.36	14	17
Seacoast - Westville Tap 58X1	2,260	506.87	10,636	107.70	11	18
Seacoast - Cemetery Lane	997	615.38	7,741	79.26	12	19
Seacoast - Seabrook - 34.5 kV	1,812	658.68	4,165	286.56	32	20
Seacoast - Guinea Switching - Distribution Circuits	1,821	585.39	7,257	146.89	22	21
Seacoast - Hampton - 34.5 kV	3,437	633.68	13,963	155.98	30	22
Seacoast - Stard Road Tap	1,044	764.02	6,614	120.60	24	23
Seacoast - Mill Lane Tap	959	1024.59	3,184	308.60	33	24
Capital - Bow Bog	841	430.99	2,417	149.96	16	25
Capital - Terrill Park - 16X4	574	572.71	2,801	117.36	17	26
Capital - Pleasant Street	1,115	766.87	10,005	85.46	20	27
Seacoast - Timberlane - 13.8 kV	2,747	535.65	7,636	192.70	23	28
Capital - Hollis - 8T1	912	515.67	2,246	209.39	25	29
Capital - Hollis - 34.5 kV	3,735	707.33	21,435	123.25	26	30
Capital - Boscawen - 13X4	1	119697.06	2,917	41.85	15	31
Capital - Boscawen - 13.8kV	3,109	584.78	8,727	208.33	28	32
Seacoast - Exeter	904	568.91	2,382	215.91	29	33

Table 11: Prioritization Model Scores

The following table provides the benefits and costs associated with the VVO project.

Year	1	2	3	4	5	6	7	8	9	10	Totals
Benefits (000s)	$0	$186	$875	$1,320	$1,795	$2,207	$2,584	$3,051	$3,501	$4,243	**$19,763**
Capital Costs (000s)	$383	$2,000	$2,929	$2,731	$2,862	$2,880	$3,416	$3,488	$4,292	$2,783	**$27,764**
O&M Costs (000s)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
Total Costs (000s)	**$383**	**$2,000**	**$2,929**	**$2,731**	**$2,862**	**$2,880**	**$3,416**	**$3,488**	**$4,292**	**$2,783**	**$27,764**

Table 12: VVO Benefits and Costs

Traditionally, utilities including the Company have used local control to operate their voltage regulators, LTCs, and distribution capacitor banks. These devices incorporate inputs from locally available measurements such as voltage or current and are set to accommodate a wide range of operating conditions from peak load conditions to light load conditions. These devices act independently of other devices on a given circuit or feeder, which may result in suboptimal affects across the circuit.

The technology has improved to the point where implementing VVO equipment and software can reduce line losses by optimizing the distribution system. Circuit optimization is affected by many different factors across the circuit such as substation bus voltage, end of line voltage, types and sizes of loads, length of feeder and type of conductors, as well as the size, quantity and type of DER located on the circuit. The ever-changing load and DER conditions make optimizing a circuit very challenging.

VVO utilizes dynamic operating model of the system in conjunction with real-time information from the field and runs this information through a complex optimization algorithm to optimize the performance of the distribution system. The system model and algorithm combined with remote field measurements and control enable the circuit to be optimized based upon minimizing power loss or demand while maintaining acceptable voltage profiles on each distribution circuit. VVO operates by trying to optimize voltage regulation (voltage regulators, LTCs and reactive compensation (switched capacitor banks). Effective VVO programs have been proven to typically reduce demand by 2-4%.

6.1.4 Supervisory Control and Data Acquisition

Presently, SCADA is implemented to some extent at most of the Company's substations (but not all) and only minimally for devices on distribution circuits beyond the substations. Additionally, some existing SCADA implementations use out-of-date equipment that cannot be integrated with modern SCADA functions or the new ADMS. Furthermore, at many locations that presently have some level of existing SCADA capability, it is incomplete to the extent required by the modern grid. Therefore, this project will upgrade or replace SCADA equipment that cannot be integrated with the new ADMS, and add or expand SCADA functionality at locations and equipment involved in VVO or other modernization projects. Included with this work is the replacement of older control devices or primary equipment that cannot be easily integrated with modern SCADA functions, and the addition of ancillary components (e.g. instrument transformers, auxiliary switches, etc.) to provide other necessary measurements or indications.

6.1.4.1 Description

The objective of this project is to implement key SCADA functionality at all locations needed to support the ADMS/OMS/VVO applications and other modernization projects. SCADA provides for the remote monitoring of conditions on the electric system and the remote control of equipment and functions by operating personnel or automation systems. The SCADA project is an enabling technology for other projects in the GMP including the ADMS/OMS/VVO applications. In conjunction with other components of the Plan, it will support the GMP objectives of reducing the effects of outages and optimizing demand.

The implementation of SCADA at substations typically involves the installation of a remote terminal unit (RTU) at the site, the interconnection of the RTU with local devices and sensors, the establishment of communications between the RTU and the remotely-located SCADA Master system, and the associated programming to implement the desired SCADA functions. The implementation of SCADA at standalone devices on distribution circuits (e.g. reclosers, capacitor banks, voltage regulators, etc.) does not necessarily require an RTU, and can often be achieved with the installation of communications directly to modern device controllers.

Finally, some of the existing power system equipment that will be necessary to provide the needed measurements or that will otherwise be put under SCADA control are either absent or not suitable for this purpose (e.g. hydraulic reclosers, obsolete controls, etc.). Therefore, this SCADA project will also drive the replacement of that type of equipment and the installation of additional ancillary devices to better facilitate SCADA deployment.

6.1.4.2 Benefits

In addition to facilitating the ADMS/OMS/VVO and other modernization projects, SCADA monitoring and control at the distribution level is foundational to reducing outage response and restoration times through improved outage awareness, fault location, isolation and system reconfiguration capabilities, both manually or through automation. After implementation, it is estimated that outages originating at SCADA-controlled devices may be reduced by 5 minutes of response time at the front-end and 5 minutes of re-energization time at the back-end of an outage for a total savings of 10 minutes. For the UES system, an estimated reduction of 10 minutes off of each circuit-level outage results in just shy of 800,000 customer-minutes of savings for the year 2020. These benefits will be assumed to start at 10% of the total (approximately 80,000 customer-minutes) and increase by 10% each year over the duration of the 10 year plan.

The following functionality is intended for the devices where these SCADA additions or modifications are planned:

- Real-time telemetry and historical interval data collection for each included power transformer and circuit position, including the following measurements:
    - Voltage
    - Current
    - Active and Reactive Power
    - Active and Reactive Energy (where required)

- Remote monitoring of live/dead states of included buses, lines and circuits
- Remote monitoring and control of included breakers, reclosers, switches, etc.
- Remote monitoring and control of included transformer LTCs and voltage regulating transformers
- Remote monitoring and control of included capacitor banks
- Integration with the ADMS, and the ability to participate in automation schemes suitable to their functions

6.1.4.3 Project Timeline and Cost Estimate

The implementation of the ADMS, VVO, FAN and SCADA projects are closely tied together. The following timeline and cost estimates reflect emphasis on the necessary additions and modifications to integrate existing SCADA sites into the new ADMS in the first few years, followed by the extension and expansion of SCADA functionality in subsequent years to coincide with the VVO deployment plan. Year 1 of the project plan is expected to be 2022.

Year	1	2	3	4	5	6	7	8	9	10	Totals
Benefits (000s)	$ 182	$ 359	$ 536	$ 713	$ 890	$1,067	$1,244	$ 1,421	$1,598	$ 1,775	**$ 9,786**
Capital Costs (000s)	$1,530	$1,740	$ 760	$ 790	$ 250	$ 340	$ 420	$ 550	$ 760	$ 470	**$ 7,610**
O&M Costs (000s)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ -**
Total Costs (000s)	**$1,530**	**$1,740**	**$ 760**	**$ 790**	**$ 250**	**$ 340**	**$ 420**	**$ 550**	**$ 760**	**$ 470**	**$ 7,610**

Table 13: SCADA Benefits and Costs

SCADA deployed in distribution substations and on distribution circuits allows grid operators to monitor and control distribution equipment remotely from the dispatch center. This capability will manage the reliability and operational efficiency of an increasingly complex distribution system. Historically, emphasis was made on implementing SCADA for monitoring and control of transmission systems. Installing SCADA on the distribution system was considered secondary and not as important as having control of the transmission system. Grid modernization will require as much control and information on the distribution system as possible.

6.1.5 Mobile Damage Assessment Platform

This project is to implement a Mobile Damage Assessment Platform to enable quicker, better-informed decisions to ensure operational efficiency and maintain strong restoration performance by significantly reducing the amount of time for field information to be relayed. This would allow for faster and more accurate situational awareness during large scale weather events.

6.1.5.1 Description

UES has researched and evaluated various applications that will expedite damage data acquisition, develop fasters ETR's, enhance overall situational awareness and produce more efficient work packages that will, in turn, expedite the overall restoration. The project team developed an RFP and evaluated proposals from 13 different vendors.

The mobile platform damage assessment system will be an application based system that will replace existing paper based damage assessment and inspections presently used by the Company. This system will allow damage to be collected on the mobile application including the location, the type of damage and pictures. This data will automatically be transferred back to the back end system portal in the office where ETRs and work packages can be developed, issued for repair, tracked until completion.

The following capabilities are technical requirements for the mobile platform damage assessment application.

1. Data collected by the platform must be fully accessible via a documented application programming interface (API).
2. The platform must be capable of rendering output in a device agnostic, fully responsive manner, compatible with all major mobile, laptop and desktop devices
3. The platform must be capable of high availability, redundancy, high-capacity storage and industry standard security and compliance
4. The platform must have the ability to consume data from legacy applications
5. The platform must have documented APIs allowing the Company to build its own connectors
6. The platform must support direct integration with GIS
7. The platform must support the ability to capture, store and display rich media content such as photos, video and audio files.
8. The platform must support the ability to work offline / without real-time connectivity to the internet
9. The platform must support offline mapping
10. The platform must support integration with Active Directory for Single Sign On
11. The platform must include the ability to capture GPS coordinates and geo tag records and collected assets with this data
12. The platform should have no cap on the number of applications or the number of records that can be collected by a given application
13. The platform must support, at a minimum, two discreet environments for testing and production
14. The platform must support electronic signature capture
15. The platform must include audit logging capabilities to capture transactional history
16. All Systems that Handle Confidential Information must encrypt the data that include Confidential Information in transit using algorithms and key lengths consistent with the most recent NIST guidelines.
17. The initial application built on this platform will be for the Company's Damage Assessment system. However, there are a number of additional areas wherein real-time information exchange would result in more effective work flows. Future applications may include (but are not limited to): Asset inspections, Mobile Workforce Management, Mobile Work Order Management and Outage Management

The project team is comprised of various company employees who have responsibilities either during routine or emergency times for processes and activities related to damage assessment and inspection. The evaluation team includes key members from the Electric Operations, Engineering, and IT departments as well as other employees who have emergency assignments related to Damage Assessment.

After the initial review and evaluation, several vendors were invited into the Company to provide a presentation on their proposal so that the project team could a clearer understanding of their proposal and have questions answered. Following the vendor presentations, the evaluation matrix was updated.

After several meetings and weeks of deliberation by the project team, it was ultimately decided that the best solution was the Mobile Information Management System (MIMS) powered by Lifecycle proposed by SSP Innovations. The MIMS solution will be synchronized with the Company's GIS systems and is designed to perform electronic field inspections of assets and vegetation while also providing the ability to create workflows, assign and track work assignments, and estimate cost, labor and equipment associated with work orders.

Throughout this project, the Company has learned that mobile damage assessment is just one of the functionalities that this software platforms can provide. Other functionality includes asset management, inspections, or other workforce management tools with several proposals including many of these features included within their products. The Company is interested in additional functionality in the future and has included the additional functionality available from the vendor offerings during their evaluation.

6.1.5.2 Benefits:

The application will have several benefits related to operations and planning including the ability to confirm, validate and document predicted devices leading to a greater accuracy of affected customer counts, outage causes and times of restoration. Field damage assessment information will also allow work orders to be tied to actual damage or repair work geographical areas and will also provide the Company with faster field information to better estimate and identify the types and amounts of specific resources needed and better identify when resources will no longer be needed. The Plan estimated that this is expected to save on average 15 minutes per outage during a major event.

6.1.5.3 Project Timeline and Cost Estimate:

The project has been initiated and is scheduled to be completed prior in early Q3 2021 ahead of the busy hurricane season.

Year	1	2	3	4	5	6	7	8	9	10	Totals
Benefits (000s)	$946	$946	$946	$946	$946	$946	$946	$946	$946	$946	**$9,460**
Capital Costs (000s)	$449	$-	$-	$-	$-	$-	$-	$-	$-	$-	**$449**
O&M Costs (000s)	$-	$35	$35	$35	$35	$35	$35	$35	$35	$35	**$311**
Total Costs (000s)	**$449**	**$35**	**$35**	**$35**	**$35**	**$35**	**$35**	**$35**	**$35**	**$35**	**$759**

Table 14: Mobile Damage Assessment Benefits and Costs

6.1.6 AMI/OMS Integration

This is a software project to enhance the current AMI to OMS interface. The Company has already implemented an AMI system across its service territories. This enhanced integration will provide improved ability for all AMI meters to communicate with the OMS system in a more reliable manner resulting in greater confidence in the data presented. This enhanced data will be used in the OMS outage engine to help improve outage predictions, including which device has isolated the fault and what customers have been restored.

6.1.6.1 Description

UES's AMI system provides information on outages for every meter on the system. This project is designed to improve the integration of outage information from meters into the OMS outage prediction engine, thereby improving the outage prediction process, reducing false positives and improving the ability to identify the location of nested outages.

UES's OMS system relies on customer outage calls processed by the IVR system, web outage form entries, and manual entries of customer and municipal calls to determine the location and extent of outages. Most outages are reported by only a small percentage of customers contributing to the outage information (typically, only 1-2% of the customers notify the Company when they are out of power). This small percentage of customer notifications may lead to an erroneous outage location and extent, or delay the field trouble shooting process.

UES's AMI system is currently integrated with OMS as a "view only" overlay. The AMI system communicates with all meters through a parallel channel power line carrier (PLC) system. Essentially, the system continuously communicates with all the meters on the system while data collectors in the substations transmit meter status to the head end software system called the Command Center. Changes in meter status are shared through live integration with the OMS where they can be represented visually. Because communication with meters could be lost for reasons other than an outage (e.g., noise on power line, loss of AMI network communications), the Company does not use this information in the algorithm for modeling outages in OMS. Instead, the visual AMI information is presented in OMS to help determine the extent of the outage (i.e. all outage meters go "lost" or red when they lose power) and the extent of restoration (i.e. all restored meters restored become "found" or green).

The figure below shows a partial restoration of an outage. The red icons indicate customers still out, the green are customers that have been restored.

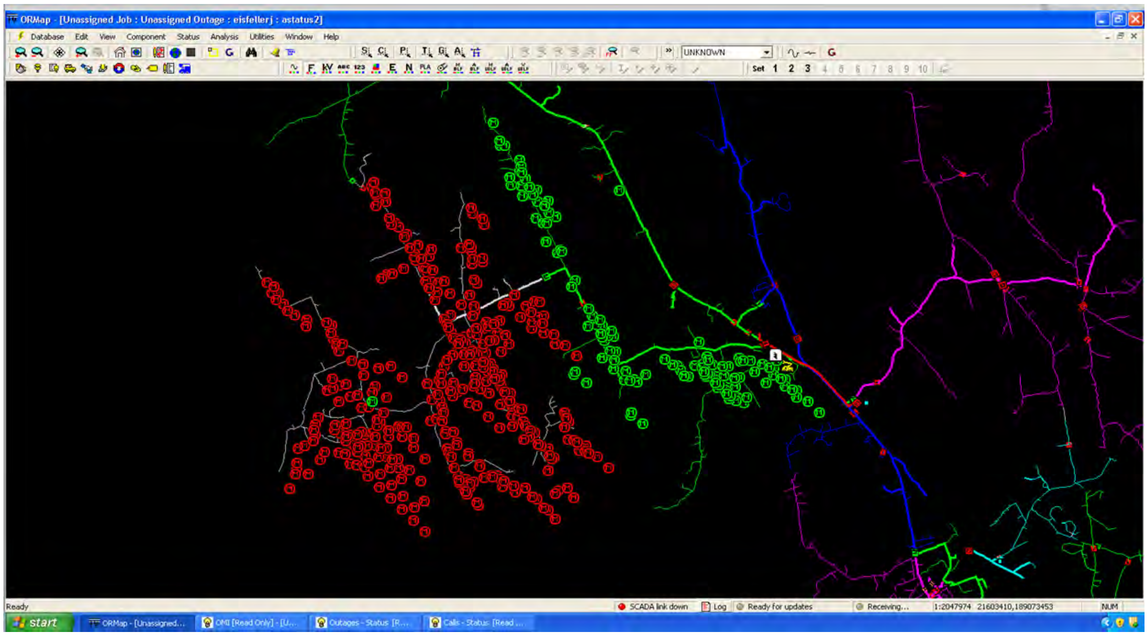


Figure 5: the Company's AMI Meters in OMS

UES is developing a piece of configurable "middleware" (i.e. software) to analyze AMI status changes along with additional relevant data points, and computing an "AMI Confidence Score" for AMI based customer outage reporting. Based on the configuration of the middleware, suspected outages above the allowed "confidence score threshold" will be treated as "real outages" and reported to OMS as such. Those that fall below the threshold will be logged and sent to OMS for view only. This threshold is adjustable by the dispatcher to allow some level of active customization.

The system will leverage a set of correlating data inputs such as historical outages, low level signal data, modem communications status and weather data along with machine learning models to assist in computing outage confidence.

UES has worked closely with our AMI vendor (Landis & Gyr) to identify a combination of data points available on the meter and the AMI collectors along with various correlating data points (environmental and coincident) to build a model that can accurately confirm suspected outages and electronically qualify them.

The project has been broken down into two phases (both are included in the project):

Phase 1 – AMI Confidence Engine & Filter

Although our Landis and Gyr AMI system has functionality to detect and report on meter/ endpoint level outages, the results we see are unreliable to the point that the Company has chosen not to directly integrate the AMI data for outage model calculations. A meter black list construct was implemented where known bad reporting endpoints could be grouped and ignored by any auto outage detection. However, there is no easy way for the Company to dynamically move meters on and off this "outage reporting black list", which makes it a largely static list. If, for example, we make improvements to a network segment of previous blacklisted meters; even though these meters could likely better participate in the AMI auto detection after the upgrade is completed, they will not be able to, because they are part of this hardcoded black list.

The Company is making use of this automatic detection process and accompanying data in an effort to improve our ability to detect and respond to customer outages. The Company also believes that it can augment the existing

Landis & Gyr detection algorithm with an additional algorithm leveraging readily available data to correlate and further qualify (by way of a "Confidence Score") suspected outages.

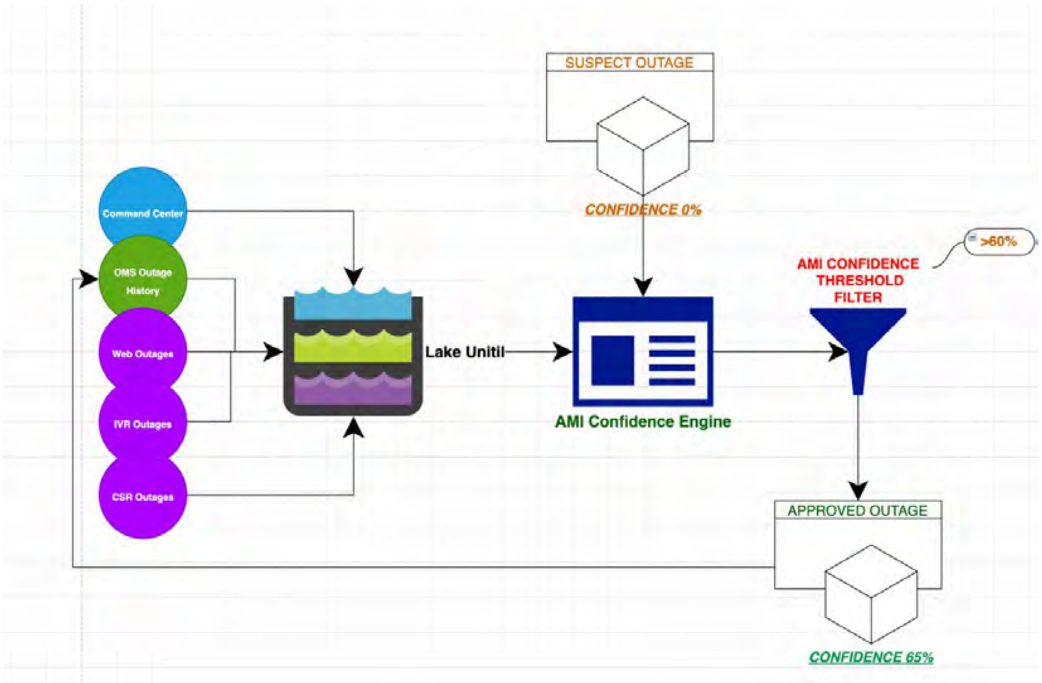


Figure 6: AMI/OMS Phase 1 Diagram

ACE Filter - The ACE Filter is a software service that is responsible for evaluating the confidence score attached to an outage and determining if the score meets or exceeds the configurable confidence threshold (dispatchers would be able to dynamically adjust this threshold up or down). Any outage that meets or exceeds the threshold is allowed through the Filter. Any outage failing to meet the criteria is rejected, logged and a notification is sent. No changes would be required to the core OMS functionality as the filter would handle pre- screening outages before sending them along to OMS.

Lake Unitil - Our data warehousing "lake", will contain data from our Command Center, OMS and enQuesta systems to start. The application development team will build out data load scripts to populate and maintain this Data Lake. It is helpful to think of a data lake as a large data warehouse in the cloud that contains data in a variety of different formats (*XML, flat unstructured data files, CSV and traditional relational data). The ACE will use the data contained in this lake to make its confidence scoring decisions. In later phases, additional data points such as vegetation, social media, behind the meter status and weather could be added to the data lake and augment the algorithm.

Phase 2 – Additional Data Sources

In this phase of the development the Company will include additional data sources into the confidence interval. Specifically, this plan includes the collection and combination of data sources for weather as well as signal to noise ratio (directly from AMI Collectors) into the confidence engine. Quality control, testing and deployment, as well as ongoing support of the system are included.

Project Summary

This project will combine AMI status information, modem status information, and current outage input data (IVR, Web, and manual entries), and process this information through a series of software filters and logic to allow AMI information to be used in the outage algorithm. The goal will be to develop this filter to the point at which there is high confidence in the result (i.e., the AMI status change is a result of an actual outage). If a high confidence is achieved, the AMI data will allow the Company to determine the probable location and extent of an outage in a shorter timeframe, resulting in improvements in outage response time estimates and related customer communications.

The Company continues to research machine learning tools, data science techniques, and cloud technologies to determine the best approach for building applications that will help to determine and calculate the confidence score.

The proposed upgrade will allow AMI outage information to be used directly in the AMI outage prediction engine for outage reporting if the AMI status change has an associated high confidence factor. This AMI information should improve timeliness of outage detection, dispatch, extent and restoration.

6.1.6.2 Benefits:

By proactively detecting, and confirming with a high degree of confidence, valid outages, we expect to save time and money by reducing potentially unnecessary truck rolls and expedite crew deployment. This data may also provide additional near term related benefits such as reduction in SAIDI times as well as long term applicability towards building more proactive and predictive outage intelligence and analytics. The theory is that the outage information from the AMI system will allow the Company to know about the outage without having to rely on a customer phone call through the IVR system. It is estimated that the AMI system on average will be five (5) minutes faster than customer calls for at least 10% of the outages. This system will also give near real-time restoration feedback and provide insight into any "nested" outages that may require follow up by crews.

6.1.6.3 Project Timeline and Cost Estimate:

This project is an internal software development project. An off-the-shelf solution does not exist for this application. The phased approach to the project enables internal software developers the ability to design and implement the project in a staged manner. Testing and verification of the system will occur in conjunction with the Company's dispatchers.

Year	1	2	3	4	5	6	7	8	9	10	Totals
Benefits (000s)	$0	$163	$163	$163	$163	$163	$163	$163	$163	$163	**$1,463**
Capital Costs (000s)	$$155	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$155**
O&M Costs	$0	$11	$11	$11	$11	$11	$11	$11	$11	$11	**$99**

(000s)											
Total Costs (000s)	**$155**	**$11**	**$11**	**$11**	**$11**	**$11**	**$11**	**$11**	**$11**	**$11**	**$254**

Table 15: AMI/OMS Integration Benefits and Costs

6.1.7 Distribution Automation

A reliable distribution system is important to the Company and its customers. Distribution automation provides the Company with the ability to automatically change the configuration of the system based upon changing load or generation characteristics. Distribution automation can also detect outages and automatically restore portions of the system within minutes thus reducing the overall size of the outage.

UES implements targeted distribution automation where projects make sense. Projects generally consist of installation of recloser, sensors and communication equipment to allow the devices to communicate with each other. Distribution automation projects target portions of the system that have been identified as candidates to benefit from the installation of distribution automation. These areas have the ability to automatically shift load from one circuit or substation to an adjacent circuit or substation to isolate the faulted section and restore customers. The table below identifies the benefits and costs associated with distribution automation. The primary benefit of this project is the ability to restore customers within minutes of the initial outage reducing the number of impacted customers as well as the customer minutes of savings.

Distribution automation is not a new concept to the utility industry. Technology advancements in communication speeds, fault sensing, and switching capabilities has made distribution automation more cost effective. Distribution automation has the capability to achieve substantial reliability savings. Improved fault location, isolation and service restoration result in fewer and shorter duration outages, reduced equipment failure, lower outage costs for the customers and the utility and less inconvenience for customers. Overall system resilience to extreme weather events improves with the ability for automatic switching reducing the overall impact of outages and provides the operator with greater information to identify and repair equipment. Distribution automation can reduce the number of truck rolls and reduce the amount of time required for service restoration. Integration of DERs can also be improved with distribution automation schemes.

UES is not proposing any specific distribution automation projects at this time. As part of annual reliability analysis, specific projects may be proposed at a later date. The implementation of a field area network and SCADA will support a wider scale deployment of distribution automation.

6.2 Advanced Metering Functionality

The modern electric system is driven by data and information. Customers need data to inform their usage decisions. Customers desire flexible pricing options that allow them to take advantage of their investments. Customers need to know how much electricity they are using and when that electricity is being used. Customers are willing to reduce their peak hour usage as long as they have the knowledge and tools to achieve the benefits. Timely and user-friendly data starts with a metering system that can accurately and automatically gather granular usage data, store the data in a meter data management system where it can be pushed to customers in a timely manner.

The Company implemented an automated metering infrastructure system that uses powerline carrier based technology. Powerline carrier uses the electric system primary conductors to communicate commands to the meters and transmits data from the meters back to the head-end system. This two-way communications technology is highly reliable and highly secure.

The Company's original AMI installation was state of the art when it was installed but has been outpaced by new technology that can provide more information in a more timely fashion. The Company recently completed an upgrade of the substation collectors that will allow interval meter readings to be transmitted once an interval meter has been installed. This will support the Company's plan for implementing time-of-use rates for various use cases.

Meter replacements will be tied directly to the TOU enhance rate offerings being proposed as well as the Customer Experience Management System. In order to obtain the full benefits from these offerings, the existing TS2 meter must be replaced with a PLX meter that enables interval metering. At the present time, the Company is not proposing a particular project for replacement of the endpoints and meters outside of meters that will be replaced to enable TOU rate offerings. However, as meters are replaced for maintenance or testing, they will be replace with PLX technology that enables interval metering.

6.3 Distributed Energy Resources, Energy Storage and Controllable Loads

The growing proliferation of distribution-connected DER and increasing interest in energy storage systems and controllable loads creates new opportunities and challenges for the electric system. The Company's vision of the advanced grid is an enabling platform with the ability to interconnect a large quantity of renewable resources and other DERs.

6.3.1 DER Reverse Power Flow and Sustained Energization Mitigations

As the proliferation of DER on electric distribution systems increases to levels approaching that of the local distribution loads, challenges caused by reverse power flow and sustained energization become more prevalent. These challenges include adverse impacts on voltage regulation, short-circuit protection and overvoltage protection.

At present, mitigations to accommodate the interconnection of DER are identified during impact studies of individual DER projects, and the associated costs are borne by the specific DER project owner(s) rather than electric customers in general. Therefore, there are no generalized projects included as part of this GMP to preemptively mitigate adverse effects of DER.

6.3.2 Energy Storage

Energy storage technology will play an important role in the integration of intermittent renewable resources. Energy storage system provides the energy and capacity when intermittent resources such as solar or wind might be lacking. However, combining renewable generation with an energy storage system will improve the reliability, capacity and availability of the intermittent resources to a point where the system can rely on them when planning the system.

FG&E has installed its first utility scale energy storage facility in Massachusetts. The justification for the energy storage facility is based upon a non-wires alternative evaluation. The 2 MW/4MWh utility scale energy storage system is designed to defer the need for a costly substation expansion. The energy storage system has the ability to serve over 1,300 homes for over two hours. This energy storage system is designed to reduce peak loading on the substation equipment as well may provide voltage regulation and frequency regulation to the market. This is a significant size energy storage device equating to over 2% of the system peak for the Massachusetts service territory. Based upon the Company's experience, utility scale energy storage can be installed for approximately $2 to $3 per watt.

The energy storage system is designed to dispatch the battery in a manner that provides the most benefit to the Company and its customers. At the time of substation peak, the battery will be discharged to reduce loading on the substation transformer as well as lower the overall system peak which will reduce transmission capacity costs to our customers.

The energy storage system may also be entered into the ISO-NE frequency regulation and capacity markets. ISO-NE will have the ability to dispatch the capacity at the time it needs for frequency regulation as well as reducing our peak hour loading that is used to calculate our capacity charges. The energy storage system produces a revenue (savings) stream that will directly benefit our customers by reducing their bills without needed to take any action on their own.

The energy storage system is the first installed on the Company's system. The Company intends to learn from this non-wires alternative (NWA) project and confirm the benefits to the distribution system and its customers. Reliable operation of the energy storage system during the peak hours is important to the deferral of the substation expansion.

This is one example of a utility scale energy storage installation. Behind-the-meter energy storage can also be effective at shaving peak load and accounting for intermittent DERs on the system. At this time, the Company is not proposing a particular project. However, energy storage will continue to be an alternative that is reviewed and proposed as part of NWA analysis.

6.3.3 Electric Vehicles

Electric Vehicle (EV) adoption rates are reaching a tipping point where customer desire will rule over price point. Electric system planning must accommodate the additional load while providing incentives and rate mechanisms to encourage customers to charge vehicles during off peak hours.

UES is proposing a two pronged approach to electric vehicle charging. First, effective EV charging rates incent customers to charge their EVs when it is most beneficial to the system during nighttime hours. Improving load factor during off peak hours allows the system to operate in a more optimized manner. Second, the system needs to be planned in advance for the increase in EVs. System planning that considers DER, including generation resources, on the system in combination with controllable loads enables the utility to design and operate a safe and reliable grid. Controllable loads such as EVs may benefit the system during times of peak PV as well as low loads during the shoulder months of the year.

UES is proposing a public EV Program that includes make-ready infrastructure investment to provide for the installation of required electrical infrastructure up to the charging station with no customer contribution. The Company will own all infrastructure up to the charging station (including assets behind the meter). The Company will install the infrastructure on the utility side of the meter and would contract with third-party electrical contractors to install infrastructure behind the meter. Applicable customers will be required to enroll in corresponding EV TOU rates and provide the EVSE at their cost.

UES's investment will include (but not be limited to): distribution primary lateral service feed, transformer and pad, service meter, service panel, construction, conduit and conductor necessary to connect the EVSE. The program is focused on public Level 2 and DC Fast Charging (DCFC) stations. Economic analysis of the proposed EVSE program using the Company's internal rate of return primarily used for evaluating electric expansion projects has demonstrated the prudency of these investments.

This program will be presented separately from the overall Grid Modernization Plan.

6.3.4 Active Demand Response Program

When appropriate, the Company will implement an Active Demand Response Program ("ADRP") approach as a Non-wires Alternative ("NWA") to defer the costs of traditional infrastructure upgrades and improvements. This approach will be open to all DER approaches that display the potential to provide the load relief described in this document. These approaches could include a combination of customer load curtailment, storage, generation, and/or any other approach deemed appropriate for a particular site as well as Company owned assets such as storage and/or generation. Generally, these approaches would apply to C&I customers' equipment and Company owned equipment.

Each instance would outline the suggested approach, load relief impact, cost estimate of completing the project, project schedule, quantifiable benefits, and net lifecycle cost (installed, maintenance, and operations costs minus quantifiable benefits) compared to a traditional approach.

Since the upgrade and/or improvement projects would be of a critical nature, the NWA demand reduction approach would have to be available when needed and available over a period of years.

Customer C&I Load Curtailment

This approach is technology agnostic and provides an incentive for verifiable shedding of load in response to a signal or communication from the Company coinciding with circuit peak conditions. Customers would be incented based on their average performance but must be available for all events and meet a minimum pre-determined load curtailment level. The typical technologies or strategies used to curtail load may include:

- Energy management systems,
- Building management systems,
- Software and controls,
- HVAC controls (manual, networked system or integrated),
- Lighting with controls (manual, networked system or integrated),
- Process offsets,
- Any open ADR compliant technology,
- Properly permitted generation,
- Startup sequencing, and

- Other customer facility specific approaches.

Since the approach is technology-agnostic and performance-based, the Company will be able to incent the performance of customers adopting innovative and emerging demand reduction technologies, including energy storage technologies (see later section). Customers can use any technology or strategy at their disposal and earn an incentive based on their curtailment performance. To participate, customers must be able to contract not only for a kW reduction amount but for a number of years' commitment.

Customer C&I Storage Performance Approach

The C&I Storage Performance approach recognizes that Large C&I customers with demand charges, direct capacity costs, and time of use rates have a different value proposition from residential and small and medium C&I customers. C&I customers installing storage will have the same obligations and opportunities as the C&I Load Curtailment option. Due to the increased capital and operating costs of such projects, customer and developer risk, and lack of current clear access to or mutual exclusivity of revenue streams for energy storage technologies, the Company would have to offer increased performance incentives for C&I storage performance, significantly above the proposed technology-agnostic Interruptible Curtailment performance incentives discussed above.

For both customer options, the Company will establish incentive levels, number of years' obligation, penalties for non-performance and other parameters for participation deemed necessary to meet the specific load relief requirement. The capacity reduction requirement will include a capacity premium designed to compensate for non-performance or reduced performance from participating loads for any given event.

UES would likely need to procure more kW than the C&I Curtailment commitment and the C&I Storage Performance commitment to mitigate the risk of non-performance and ensure designed capacity requirements are met. Customers may bundle Curtailment and Storage into one project.

See the table below as an example for commitments needed for a 5,000 kW traditional upgrade.

	Curtailment kW	**Storage kW**	**Company Owned kW**
Scenario 1	5,000 (6,500)	-	-
Scenario 2	3,000 (3,900)	2,000 (2,300)	-
Scenario 3	2,000 (2,400)	1,500 (1,750)	1,500 (1,500)

Table 16: Example Demand Response

Note: numbers in ( )'s indicate the commitment needed

Company Owned Load Curtailment and Storage:

UES will also evaluate a Company Owned Equipment ("COE") approach by installing generators, storage, and/or alternative technologies or approaches yet to be readily or commercially available. These can be combined with customer curtailment and storage strategies to meet the capacity requirement.

Detailed Discussion of Benefits and Costs:

Costs and benefits are site specific. From a benefit perspective, there are monetary and non-monetary benefits associated with each NWA project. This is similar for costs. Projects could be made up of a combination of two or more approaches. Potentially, the life of NWA approaches could be fairly less than a traditional investment, which would lead to equipment replacement sooner than a traditional investment would need replacement. Quantifiable estimated costs for various approaches are included in the table below.

		NWA		
Technology/Approach	Cost/ kW installed	Unitil Upfront Incentive or Cost	Unitil Incentive Annually P4P Cost/kW	Total cost/kW over 10 Years
Customer Owned [1]				
Battery Storage	$ 1,500	-	$ 200	$ 2,000
Gas Generator	$ 1,000	-	$ 175	$ 1,750
Diesel Generator	$ 900	-	$ 175	$ 1,750
Demand Response	-	-	$ 100	$ 1,000
Energy Efficiency [2]	$ 2,000	$ 3,000	-	$ 3,000
Company Owned [3]				
Storage	$ 1,500	$ 1,500	-	$ 1,500
Gas Generator	$ 1,000	$ 1,000	-	$ 1,000
Diesel Generator	$ 900	$ 900	-	$ 900

[1] Customer responsible for maintenance, taxes, permitting and fuel - not included in costs
[2] Based on weighted average incentives and costs from 2018-2020
[3] Company responsible for maintenance, taxes, permitting and fuel - not included in costs

Table 17: Representative Costs by Approach

In general, Load Curtailment is the lowest cost option. At the same time, it is the most difficult to procure and maintain the level of savings committed since it relies on large commercial and industrial customers that either may not exist on a particular circuit, may not have interest in participating, do not have the Load Curtailment opportunities or after committing to the program reduce the level of participation or stop participating. The Company is not proposing a particular project associated with demand response at this time. Demand response will be evaluated as part of a NWA analysis and implemented where cost effective.

6.4 Advanced System Planning

Real-time system planning is foundational to the optimization of the electric system. The modern grid is constantly changing. Intermittent generation resources and added loads from electrification can drastically change operating conditions within moments. Real-time system planning enable grid operators the tools to make the necessary adjustments to optimize the system. Real-time system planning increases the safety, reliability and security of the electric system. In addition to the Company's GIS system and its new methodologies for electrification and DER forecasting, the Company is focused on two new initiatives: hosting capacity analysis and map and locational value analysis.

6.4.1 Hosting Capacity Analysis and Map

Under the present tariff model, those wishing to interconnect onto electric distribution system submit an application with all of the applicable information along with the location of the interconnection. The utility then evaluates each application to determine if any system improvements are required. This process works well, but without knowledge of the general capacity and limitations of specific areas, some applications are likely to be determined to be economically impractical. If these developers or DER owners had a greater visibility into the ability for the grid to accept DER, this should reduce some of the iterative analysis by the utility and developer trying to identify a good location. The overall goal is to improve the quality and practicality of the applications submitted for review.

6.4.1.1 Description

Evaluate the existing capacity of each substation and mainline circuit to determine how much DG could be added without the need for distribution system upgrades. The results of the study will help the Company encourage the development of DG on feeders where it can be readily accommodated. The study will also identify substations that require upgrades to accommodate more DG. The general results of the study will be posted on the Unitil website as an interactive map to allow DG developers and customers to enter a proposed location to when siting future DG to receive the available capacity for the proposed location. This map will be updated annually (or sooner) to keep the information up-to-date.

6.4.1.2 Benefits:

The circuit capacity study will help the Company and DG developers to better plan for DG growth. It will also help speed the process for DG applications and system upgrades. The benefits of DER Enablement ultimately depend on how much DER is installed in the service territory. Large DG developers will no longer end up submitting multiple applications in order to identify suitable locations where DG can readily interconnect with the grid. Often times when an impact study results in system improvement, the developer cancels the project and moves on to another site. This lost time for the developer and for the Company will result in greater efficiency, lower costs and decreased time to approval to interconnect.

6.4.1.3 Project Timeline and Cost Estimate:

At the present time, the Company assumes that the only costs associated with this project is internal labor and no incremental costs are expected. The benefits are also hard to quantify due to the relatively small amount of interconnection applications received on an annual basis.

DER hosting capacity, is challenging to define, because each circuit has its own characteristics and these characteristics change over time. The hosting capacity of a feeder is the amount of DER a feeder can support under its existing topology, configuration, and physical response characteristics without affecting power quality or reliability. Many considerations need to be evaluated depending on where the DER is located. The utility needs not only to look at the grid in the area of the interconnection (i.e. transformer and wire capacity, voltage control, etc.) but they also need to determine if this installation will have any effect on the overall loading on the circuit, substation or even back flow of power onto the subtransmission or transmission systems. This is a highly variable calculation depending on the situation on each individual circuit. There are many additional concerns that require analysis on a case-by-case basis for specific applications, but general loading information can be supplied at a substation or circuit level prior to receiving specific applications.

UES will develop an approach to evaluate the hosting capacity of each substation and circuit to determine how much DG could be added without the need for distribution system upgrades. The Company's goal is to present this data in a usable manner to those who are interested in the information. The results of the study will help the Company encourage the development of DG on feeders where it can be readily accommodated. The study will also identify substations that require upgrades to accommodate more DG.

Developing the benefits for integrating DERs into the grid is a more complicated calculation than identifying the circuit capacity. The benefits include but might not be limited to the generation energy, generation capacity (distribution and transmission level capacity), reduction in losses, environmental, and other benefits. The circuit capacity study will help the Company and DG developers to better plan for DG growth. The benefits of DER Enablement ultimately depend on how much DER is installed in the service territory. No monetized benefits are assigned to DER Enablement as part of this plan.

6.4.2 Locational Value Analysis

Locational value analysis is used to determine the value a DER has to the distribution system and will service to improve the overall customer value proposition. Locational value analysis is a relatively new concept to DER interconnections but is an important consideration when trying to maximize the benefits of the DER to the system and its customers. The precise way to calculate locational value has not been developed yet, but the models continue to get more accurate over time.

Locational value analysis is difficult because conditions on the distribution system change very quickly based upon changes in load and other distributed resources. These changes can have a large impact on the value of a DER in a given location. Locational value analysis is still in its infancy. Locational value analysis is evolving as utilities understand more about the capacity, reliability, availability and life span of DER assets.

Developing the benefits for integrating DERs into the grid is a more complicated calculation than identifying the circuit capacity. The benefits include but might not be limited to the generation energy, generation capacity (distribution and transmission level capacity), reduction in losses, environmental, and other benefits. The circuit capacity study will help the Company and DG developers to better plan for DG growth. The benefits of DER Enablement ultimately depend on how much DER is installed.

Understanding locational value is essential for utilities to plan for and rely on cost-effective DER to defer distribution system upgrades. The hypothesis is that as the value of DER can be accurately calculated it will lead to more distribution system investment deferrals.

At the present time, the Company is not proposing a particular approach or project associated with locational value model development. The Company looks forward to working with the Commission and interested stakeholders in the open docket on locational value analysis. The Company intends on making any modifications to its planning process required following the outcome of the open docket.

6.5 Enhanced Customer Services

6.5.1 Data Sharing Platform

6.5.1.1 Description

UES, filed a proposed approach for data sharing in Docket No. DE 19-197. The Company's proposal here is in line with the recommendations made in testimony[1]. RSA 378:50-54 provides clear direction on several foundational components of the online energy data platform, and this proposal incorporates these items into the proposed design presented as part of the "straw proposal". Two of these foundational components are at the core of this proposal as required by the enabling statute: (1) suitability for Green Button Alliance approval, and (2) the creation of and adherence to a "logical data model". There are numerous functional use cases of value to interested parties that warrant consideration for inclusion in options for platform design. Development of the unique functionality necessary to support the specific data and output for all desired outcomes would require an enormous and potentially unrealistic level of up-front design and requirements gathering, likely necessitating a traditional "Waterfall" style software development lifecycle. "Waterfall" projects – where project activities occur in linear, sequential phases – by their nature traditionally incur a much longer time-to-launch trajectory with all of the accompanying cost and obsolescence risks that can follow. In an attempt to avoid this, an "enabling platform" is proposed that securely provides a core set of customer energy usage and billing data points in a standardized data format. The Company refers to this architecture as a "Virtual Energy Data Platform", the structure of which is depicted in the following figure.

[1] Reference Docket No. DE 19-197 Joint Testimony of Thomas Belair, Riley Hastings, and Dennis Moore for Eversource and Justin Eisfeller, Kimberly Hood, and Jeremy Haynes for Unitil.

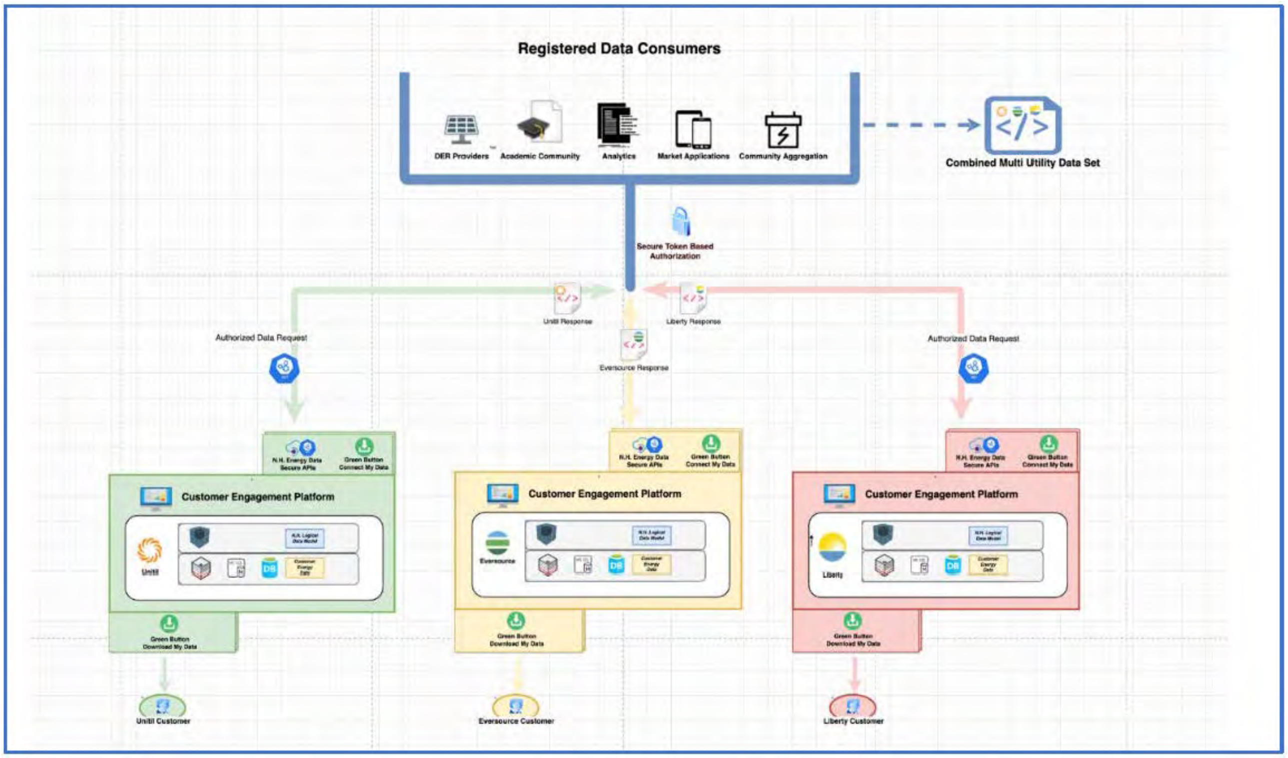


Figure 7: Virtual Energy Data Platform

The virtual platform model is designed to be extensible in an effort to provide the greatest level of cost mitigation and flexibility.

Logical Data Model

UES will have unique challenges associated with the process of mining and combining customer energy data from individual, disparate systems to the platform. Numerous technical and non-technical hurdles exist with retrieving and processing the data necessary to support the platform. For example, these data may exist in various vendor relational database systems, they may exist in flat or unstructured data files, or even in legacy mainframe systems. All of these scenarios will require the data extraction and parsing systems (the “extract” portion of the traditional ETL, or extract, transform and load model), representing a complex and non-trivial exercise.

After the Company has completed all of the work necessary to identify and extract the required data from internal systems, a second challenge unique to each company arises: combining all of the data as the result of these “extraction” efforts into a single, cohesive, data set that can be interpreted and processed by third-parties (the “transform” portion of the ETL model). Without complex standardization and coordination across the utilities, this would be a near impossibility. The introduction of a “Logical Data Model” attempts to solve some of these problems.

The model provides a common abstraction with agreed upon semantics for field names and data conventions, allowing the utilities to “speak the same language” with common terms and agreed upon units of measurement. The Energy Service Provider Interface (ESPI) data standard released and maintained by the North American Energy Standards Board

(NAESB) is proposed to be used as the basis for the model. If data fields are required that are above and beyond what is offered in the ESPI model, the desired approach is to work with the governing body to extend the model, however the standard is already quite robust containing constructs for various energy usage components such as: Usage Points, Meter Readings, Intervals, Reading Types, etc.

The proposed Logical Data Model will act as a “mapping layer” that sits on top of the native utility data sets. Because of this mapping layer, changes are not required to their existing back end systems to support this. However, it would still require a non-trivial data mapping exercise. Adherence to this logical data standard is a cornerstone of the “Virtual Energy Data Platform” as this is what allows multi-utility data to be combined by the API consumer.

Single Customer Data Download and Single Customer Data Sharing via Green Button standards

UES’s proposed Virtual Energy Data Platform specifies the use of Green Button Download My Data to provide single customer energy usage data sets directly to the customer. The utilities would allow customers to download their own energy usage data directly from their customer engagement platforms using the Green Button Download My Data standard, and the platform Logical Data Model by design will support this capability. Note that the Green Button standard does not presently accommodate multi-customer aggregated data, and as a result, a different standardized file format will be employed for that data.

Green Button Download My Data allows access to energy usage data directly by a retail customer from the utilities’ consumer-facing web portals, using a standard web browser. Vendors wishing to consume data in this format would need to code and create their own tools to read the downloaded files accessed via API. As an alternative, a helper style sheet can also be downloaded that allows the XML data to be transformed into a more “human readable” format. In addition, the platform can alternatively provide a downloadable comma-separated values (CSV) file to support smaller third parties who do not have the technical capabilities to process a Green Button XML file.

Aggregate Customer Data Download

In addition to the individual customer level energy data discussed above, SB 284 also provides a purpose for the platform to facilitate access to aggregated data, stating that: “By enabling the aggregation and anonymization of community-level energy data and requiring a consent-driven process for access to or sharing of customer-level energy usage data, the state can open the door to innovative business applications that will save customers money as well as facilitate municipal and county aggregation programs authorized by RSA 53-E.” In the data platform design presented below, varying degrees of utility-provided data aggregation tools are offered for consideration of value and usefulness.

UES is proposing a technical architecture that is designed to allow for incremental development, flexibility and scalability, while leveraging industry standards such as Green Button to allow for maximum interoperability with other systems and platforms.

Unitil Virtual Data Platform

At the heart of the Company's proposed design are three key components: the Logical Data Model, the Green Button Download/Connect My Data protocols for automated standards based data sharing, as well as a collection of robust APIs (application programming interfaces) that serve as the foundation for a virtualized data platform.

The use of the Green Button APIs will allow the Utilities to automate customer authorization and secure delivery of data directly to authorized third parties, adding ease of use and reducing complexity for customers.

GBC requires implementing multiple standards:

- NAESB REQ.21 Energy Services Provider Interface and
- IETF Oauth 2.0 (RFC 6749 and RFC 6750).

Using these standards will provide a retail customer with the ability to "authorize" a verified third party to access data provided by the utilities without any further interaction with the retail customer. The standards support the ability for the utilities to implement restricted access to these endpoints based on various screening and approval steps performed by the utilities for a given third party. Similar to data downloaded using the Green Button Download My Data standard, vendors would need to code and create their own tools to read the XML files access via the APIs. Helper style sheets can be provided to assist with rendering these XML data files into something that is more "human friendly".

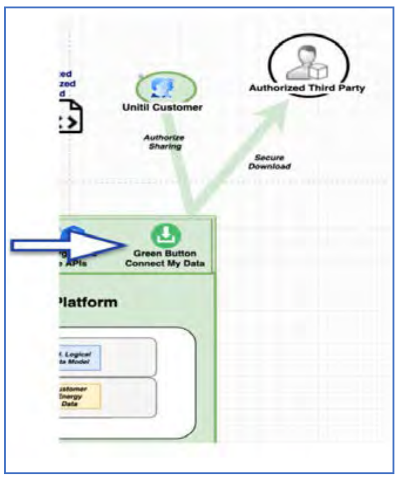


Figure 8: Green Button Download

Each participating utility will expose a library of decentralized REST accessible APIs over Secure Socket Layer connections allowing for automated retrieval and processing of multi-customer data by approved third-parties.

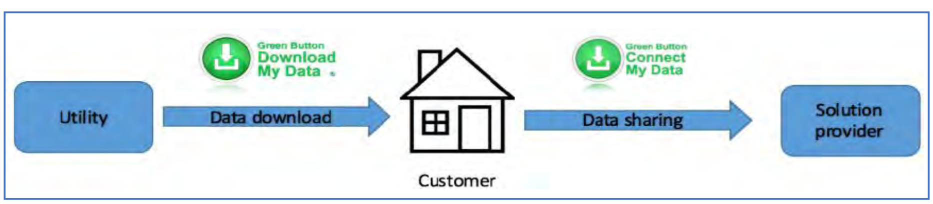


Figure 9: Green Button Download and Connect My Data Overview

The interface for these APIs, as well as the data formats returned will be exactly the same for each implementing utility and will provide standard interfaces for on-demand or scheduled energy data transfers to external requestors. Even though the back-end logic for extracting and transforming the data for each utility will be unique, the APIs will be programmed against the logical data model abstraction, ensuring simple combination of multiple Utility data sets irrespective of underlying differences in data storage, nomenclature and processing.

The APIs will implement standard token-based authentication and authorization similar to ISO-NE's API model and will return cleansed, validated and cryptographically secure data sets enabling the creation of any number of market applications and analyses. Vendors and third parties will need to request and receive an API access token in order to request data from the APIs. The API access tokens can be crafted to allow and deny access to specific granular data and data types. Once authorized, vendors and third-parties can automate analytics and combining of data using the APIs and programmatic means. Figure 12 depicting shows how single customer energy data downloads would work using both Green Button Download and Connect My Data as well as how a multi-customer (aggregated) energy use would work in a town, for example, that has areas served by three utilities.

Virtual Data Mart - Aggregation and Brokering

The decentralized API model enables many of the desired platform use cases described by stakeholders during our technical discovery sessions, but not without some additional work by the consumers of the data. For example, to retrieve and build an aggregated data set across multiple utilities, the consumer is required to make multiple API calls (one to each participating utility end- point) and combine the data themselves.

The Utilities recognize that although technically feasible, this may not represent the ideal user experience, and have designed the platform to be purpose built to allow for an "aggregation" endpoint or an "API of APIs". Doing so introduces an additional, centralized, API gateway allowing for authorized consumers to make a single call to a centrally exposed statewide API Hub that, assuming the appropriate access tokens are in place, would broker calls behind the scenes to each of the individual utility APIs and aggregate the data based on to be defined industry aggregation standards, to deliver the combined multi-utility data set seamlessly. Thus, the same data and data sets would be made available to the customer as if calling each utility endpoint individually, but that information would be provided through a single interface rather than through interactions with each utility. For individual residential customers, the incremental benefit would likely be minimal. However, to entities like commercial customers with locations in the territories of multiple utilities, the added convenience would likely be more valuable.

Virtual Data Mart - Centralized Web Portal

The API architecture proposed would also readily facilitate the creation of a centralized Web Portal that provides combined and aggregated data by municipality should the incremental cost/benefit analysis justify this work. This web portal could provide formatted reporting, stylesheets, templates and other user-friendly ways to consume aggregated data and would utilize the aggregation service and the decentralized APIs provided by the virtual platform.

Virtual Data Mart – System and Third-Party Data

As depicted below in the figure the platform also introduces the ability for viewing limited forms of system level data from the utilities and provides that data via the Virtual Data Mart. The specific types of system data offered will ultimately be determined by security considerations and the outcome of other Commission proceedings, such as the ongoing Grid Modernization docket. The Utilities acknowledge that a variety of approaches exist to solve this problem, each accompanied by unique challenges, complexities, and costs considerations. A full cost-benefit analysis must be performed to determine the value and desirability of this functionality before committing to an overly complex (and potentially expensive) solution.

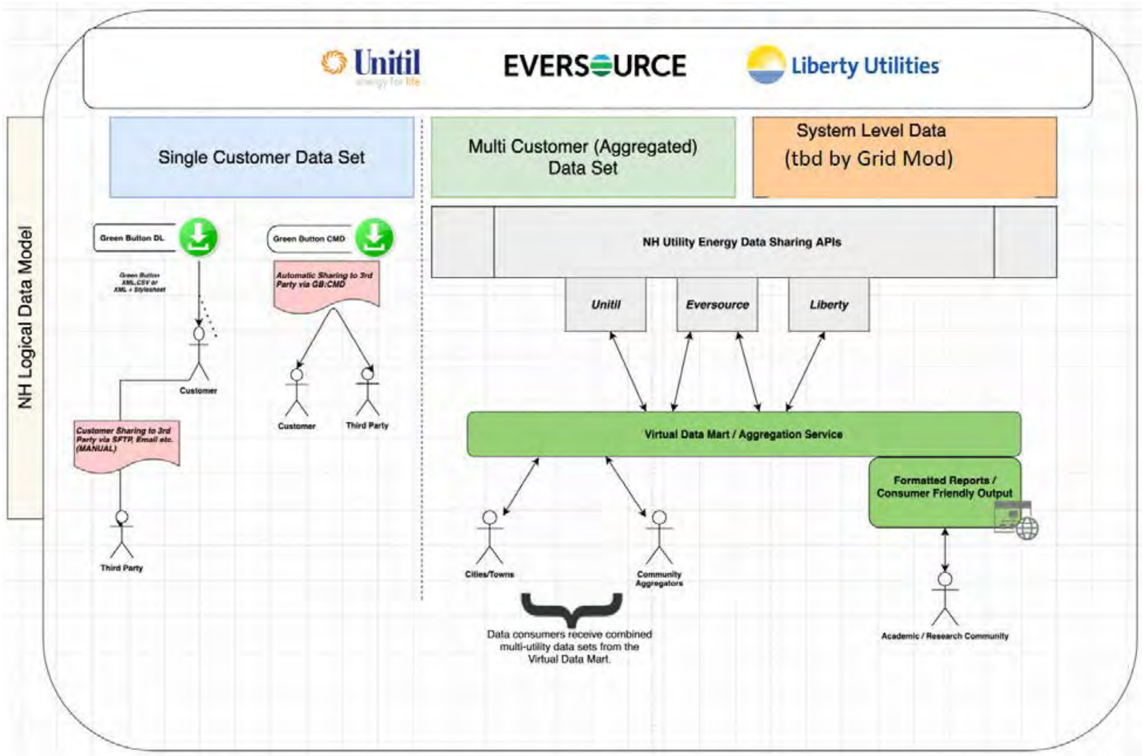


Figure 10: – Green Button Download and Connect Plus Aggregation with Data Mart

<u>Cyber Security and Privacy</u>

The Utilities recognize that data repositories storing customer data represent high-risk targets. Bad actors regularly work to steal customer information for economic gain and to support social engineering activities. The data platform is intended to contain various customer data which requires security controls to adequately protect the data. The controls proposed by the Utilities are consistent with controls currently in use. These controls are based on industry standards including the NIST Guidelines for Smart Grid Cyber Security, NISTIR 7628, and the DataGuard Energy Data Privacy Program, developed by the DOE. The platform must also ensure compliance with, at a minimum, the following state and federal mandated standards:

- PUC 300 Rules for Electric Service
- 18 CFR § 125.1 Preservation of Records of Public Utilities and Licensees
- 18 CFR § 125.3 Schedule of Records and Periods of Retention, and
- Consumer Data Breach Notification Law, RSA 359-C:19.

Understanding the threat landscape and risks helps to ensure the controls are appropriately designed. The following risk scenarios should be considered in designing data protection controls. These risks are the most significant but should not be considered all-inclusive until further information is available on the final design requirements, which could impact the threat landscape.

- Confidentiality of customer data could be compromised by unauthorized access to customer data, resulting in a data breach where the data could be sold on the Dark Web.
- Confidentiality of usage data could be compromised and used to target customers' privacy and allow an attacker to monitor behavior patterns.
- Integrity of customer data could be impacted by unauthorized access to customer data, resulting in decision-making based on invalid data.
- Unauthorized access to the data platform could result in a compromise and theft of user credentials, increasing the ability of an adversary to potentially access systems outside of the data platform and attack other energy system infrastructures.
- Third parties receiving data from the portal may not have sufficient data protection controls to ensure the risk of a compromise of customer data is minimized.
- Third-parties requesting data from the portal may be Foreign-Owned, Controlled, or Influenced (FOCI), resulting in data being provided to a nation state for purposes other than intended by the Commission or the Legislature. This situation could result in a violation of customer privacy or improve the likelihood of an attack on the power grid

While the Utilities understand that all risk cannot be eliminated, the utilities have a responsibility to ensure that customer and operational data are adequately protected, including when provided to a third party for legitimate business reasons. The Utilities plan to incorporate process and system controls into the platform, commensurate with the risk to customer privacy as well as critical infrastructure. The requirements are intended to ensure the Confidentiality, Integrity, and Availability (CIA) of the systems and data. Consistent with NIST Guidelines for Smart Grid Cyber Security, NISTIR 7628, the Utilities plan to implement a comprehensive cyber program to protect any actual data stored via the platform. These program requirements include implementing appropriate privacy impact assessments, appropriate access controls to the systems and data, security awareness training for non-utility staff that may support the portal, incident response procedures, media protection, supply chain, and appropriate system development and maintenance procedures and controls.

The following controls will be required for the platform. These controls are the key controls and others will likely be required as the system is designed:

- Access and Authentication Controls
- Configuration Management
- Encryption
- Logging and Monitoring
- Vulnerability Management

Another important step in reducing the risk of sharing Customer and Operational data is an assessment of the security posture of the third-parties that request data. The Utilities propose to adopt a common cyber security assessment process. Third-parties will complete the assessment and be certified to access data from all utilities, if appropriate. Third-parties will be reassessed annually or immediately following a change in their environment or a cyber incident. Third-parties will also be required to sign a Mutual Non-Disclosure Agreement (NDA) with the Utilities. This non-disclosure will address the requirements of the third party to protect and keep confidential customer energy use data, security and retention requirements. Additional NDAs from departments such as purchasing or IT may also be required, as appropriate.

The proposed common cyber security assessment would evaluate:

- Obligations of third-parties and contractual relationships;
- Oversight of third-party certification/vetting and annual re-certification process;
- Monitoring of third-parties for appropriate use of data;
- Liability for third-party breach of privacy rules;
- Protection of Customer Data and utility infrastructure from compromised third-parties;
- Data breach notification to utilities, customers, the Commission and stakeholders;
- Process for decertification, revoking data platform access, and third-party appeal process;
- Creation of reference materials (links, training, communications, User Guides, Business Intelligence references)

Project Build Summary

The following components make up the final build for a version of the proposed data sharing platform integrated with a multi-utility state-wide data sharing platform (such as the one proposed in DE 19-197).

- Backend data collection from source systems and mapping to Logical Data Model
- Development of UES hosted, Green Button enabled data sharing APIs that will handle all: authorization, authentication and data retrieval.
- Central Data Hub (or API of APIs) – Central aggregation point that can consume and present data from multiple utility APIs. This will be developed jointly by the utilities. These costs are not included in this proposal as the joint proposal is pending review and approval by the Commission.

6.5.1.2 Benefits:

There is a consistent trend with the data offerings that raises questions as to the value of investing in a data platform. Today, customers may download, and otherwise use their energy usage data for a variety of reasons. But to date, very few customers have leveraged these options. This project seeks to enable expanded uses for energy usage data designed for additional user types. The Utilities believe the limited engagement with current data service offerings should be taken into account when deciding the size and scope of a statewide data platform for New Hampshire. Alternatively, the Utilities understand that automating the transfer of energy data might spur more use. The actual use of customer energy data will of course be taken into consideration in the benefits when determining the cost effectiveness of implementing any solution. If the platform is utilized, it should be because the benefits of such a platform are clearly-defined and demonstrated to provide meaningful value to a sizeable number of customers.

This project will have the following benefits to our customers:

- enable customers to better manage their energy consumption
- lower monthly electric bills,
- benefit from new products and services offered;
- lower transmission capacity costs;
- deferred spending on capacity improvements;

- lower GHG emissions;
- data to support community aggregation; and
- DER providers can gain access to a larger consumer market

6.5.1.3 Project Timeline and Cost Estimate:

This project is estimated to take one year to complete. Ongoing maintenance, support and software licensing fees will apply to the platform on an annual basis going forward.

Year	1	2	3	4	5	6	7	8	9	10	Totals
Benefits (000s)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
Capital Costs (000s)	$449	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$449**
O&M Costs (000s)	$0	$41	$41	$41	$41	$41	$41	$41	$41	$41	**$373**
Total Costs (000s)	**$449**	**$41**	**$41**	**$41**	**$41**	**$41**	**$41**	**$41**	**$41**	**$41**	**$821**

Table 18: Data Sharing Benefits and Costs

Data sharing is a foundational tool that will allow customers and interested third parties the ability to use the data to inform behaviors, products and programs leading to a reduction in energy consumption. Accurate and timely data will empower customers with the information required to make educated decisions that will have a positive effect on the distribution system and customer bills. Cyber security and privacy can be a challenge with increased data sharing. The platform will be secure and ensure customer privacy above all else. Customers trust the Company to protect them and their data. Annual maintenance, support and software licensing fees will be required to keep the platform current by implementing new functionalities and programs.

6.5.2 Customer Engagement Management System

This is a proposal for continued investment in technologies designed to support the customers' experience and their satisfaction in all facets of that experience. This project will strengthen current service offerings, make enhancements to our customer web portal (or Customer Experience Management Solution), and add self-service options that enable customers to better manage their energy usage and accounts. These planned enhancements include a mobile app, artificial intelligence and chat features, and a robust notification engine to proactively alert customers regarding payment activity, changes in usage patterns, outages, and scheduled appointments.

This project will design, develop, test and implement a robust, personalized self-service solution that provides a responsive web experience, mobile application, and tailored, timely and proactive notifications for customers over an estimated 18-month period. The CEM project is a foundational element to providing customers with energy information, products and services that align with the Company's mission and strategic customer vision roadmap.

This is a foundational project that enables larger product offerings such as TOU rates and as such quantifiable benefits are difficult to calculate for this stand-alone project. The qualitative benefits include: 1) robust content management tools for web based forma and customized tools, 2) a configurable enterprise notification platform enables real-time service alerts for outage events, TOU rate conditions, and service appointments (to name a few), 3) a mobile application to improve accessibility and ease of use, and 4) provides a foundational platform that enables strategic enhancements such as predicative analytics and artificial intelligence automation.

This project will be presented separately from the overall Grid Modernization Plan.

6.6 Innovative Rate Design

Technology adoption rates continue to increase as DERs become more affordable and interconnections to the distribution system continue to increase. The Company's vision of the advanced grid as an enabling platform provides customers with the ability to achieve benefits and transform the manner in which people meet their evolving energy needs.

UES will implement a suite of TOU rate offerings to enable customers the ability to realize a benefit for their technology investment and usage patterns. TOU rates are designed to enable customer adoption of distributed energy resources, transportation electrification, and individualized energy management to reduce carbon emissions from the electricity sector while saving customer's money in the process.

The overarching objective of rate design is the development of pricing for grid services that adhere to the principles of fairness, transparency and economic efficiency. Transparent and economically efficient pricing structures will ensure a viable and sustainable long term model that provides sufficient revenue to support the modernization of the electric system. Innovative rate design encourages appropriate behaviors and assures fairness and equity among customers.

Technology innovation has both accelerated and reinforced this transformation as customers now have access to services, markets and home energy technologies previously unimagined. Advancements in technology are driving down the cost of clean energy, making it more affordable for consumers. Energy markets continue to develop as innovators develop new tools to control and manage energy usage and market new energy services directly to end-use customers.

A suite of TOU rates will help customers better manage their own energy consumption to reduce peak demand and lower system costs while enabling new technologies and distributed resources. The Company recognizes that varying customer behaviors may necessitate a suite of EV charging rate structures, including fixed rates and TOU rates. The suite of TOU rate offerings proposed includes a "whole-house" residential TOU rate, a "low demand" residential EV TOU charging rate, a "low demand" small commercial and industrial ("C&I") EV TOU charging rate, and a "high demand" large C&I EV TOU rate. These rates serve as a foundation for EV programs, energy storage BYOD programs, and other future customer investments in DERs.

One concern about adoption rates is lack of awareness or understanding of the utility bill. This concern can be compounded as rate options become more complicated with prices changing multiple times a day. Customers who invest in technology tend to be more willing to participate in alternative rate plans in an effort to receive a benefit from their investment. I

Customers who have implemented technology that can automatically shift loads are more likely to participate in alternative rate plans. Customer education is an important aspect to innovative rate design. A strong customer communication, education and outreach plan is required to support new rate offerings. Customers will be more likely to adopt new rate structures if they are aware of and understand the new rates. Offering tools that help customers compare rate offerings is critical for beneficially influencing individual usage patterns and resulting bill impacts. To educate customers more effectively, it's important to understand our customers and communicate how new rate structures can benefit them specifically. Shadow billing tools will be beneficial to customers in their evaluation of the impact different rate plans would have on their particular situation.

7 BENEFIT/COST ANALYSIS

One of the most effective ways to evaluate "foundational" grid modernization investments is on a benefit-cost basis. However, most foundational grid modernization projects do not result directly in benefits to the customer. In this case, the cost of the "foundational" investment is included in the benefit-cost analysis of the project which delivers the benefits. For instance, a FAN project in and of itself does not lead to quantifiable benefits. However, when a field area network is combined with the VVO project, the benefits can be quantified and compared to the cost. In this example, if the FAN project is evaluated as a stand-alone investment, it would never not pass a benefit-cost analysis. However, the VVO project would generally provide enough saving to pass a benefit-cost analysis, but the project will not be effective without the FAN project. A portfolio approach to all of the projects proposed will provide the best indication if the Plan as presented provides benefits that exceed the estimated costs.

The Company examined the benefits that each project could provide. Some projects were relatively easy to estimate, including those that yield operational or direct customer cost savings. Other project benefits, like those that might improve the satisfaction of customers, are harder to quantify. Benefits that improve the operation of the grid and reduce costs overall are designated as "grid" benefits while those that lower the costs for customers on their bill (reduced energy consumption or capacity), or reduce the effects of outages are designated as customer benefits. Appendix C provides the inputs and output of the benefit cost analysis.

The table below shows examples of benefits that are more or less difficult to quantify and monetize.

Easier to quantify and monetize	Harder to quantify and monetize
Operational cost savings	Value of customer satisfaction
Cost of electricity	Value of distributed generation
Value of saving energy	Value of reducing carbon emissions
Value of reducing outages	Value of reducing blackouts

Table 19: Examples of Benefits That Are Easier/Harder to Quantify

The grid modernization projects presented here support the transition to the enabling platform while delivering benefits that exceed the costs. The table below identifies the benefits and costs associated using a 20 year and 15 year NPV analysis.

20 Year NPV

Projects	NPV Benefits (000's)	NPV Capital Costs (000's)	NPV O&M Costs (000's)	B/C Ratio
Field Area Network	$0	$2,541	$586	-
ADMS and DERMS	$0	$1,855	$543	-
Volt/VAR Optimization	$21,841	$14,985	$0	1.46
SCADA	$9,040	$4,816	$0	1.88
Mobile Damage Assessment	$8,412	$385	$281	12.63
AMI/OMS Integration	$1,445	$92	$64	9.26
Data Sharing Platform	$0	$385	$329	-
Totals	$ 40,739	$ 25,059	$ 1,804	1.52

Table 20: Benefit Cost Analysis – 20 Year NPV

	15 Year NPV			
Projects	NPV Benefits (000's)	NPV Capital Costs (000's)	NPV O&M Costs (000's)	B/C Ratio
Field Area Network	$0	$2,541	$430	-
ADMS and DERMS	$0	$1,855	$451	-
Volt/VAR Optimization	$16,500	$14,985	$0	1.10
SCADA	$6,806	$4,816	$0	1.41
Mobile Damage Assessment	$7,221	$385	$237	11.61
AMI/OMS Integration	$1,241	$92	$54	8.50
Data Sharing Platform	$0	$385	$278	-
Totals	$31,768	$25,059	$1,450	1.20

Table 21: Benefit Cost Analysis – 15 Year NPV

Key Observations for Benefits and Costs

- The investments will not "pay for themselves" through operational efficiency and cost reductions alone
- The benefits primarily accrue to customers, either through electricity cost savings (the value of a kWh or kW) or the value of reducing outage minutes (Lawrence Berkley National Lab's (LBNL) ICE calculator)

- The cost savings for customers created by VVO will create downward pressure on electricity bills, even though the grid modernization investments in the STIP increase the revenue requirement – investments cost money, but customers save energy which holds the line on bills

8 METRICS

It is important for our customers, stakeholders, and Commission to have a manner in which to measure progress towards grid modernization and implementation of the plan. These proposed metrics have been influenced by the Company's experience in other jurisdictions.

Due to the complexity and data intensive nature of these metrics, the Company has not yet had the opportunity to calculate a baseline for all metrics. In some cases, the Company does not have the necessary equipment installed in the field to allow for measurement and verification. In other cases, the Company is reviewing and updating its GMP and the detailed design work has not been completed to support the development of a baseline or target. The Company will calculate baselines and targets once the metrics are finalized.

The purpose of these metrics is to determine how performance can be changed because of grid modernization activities. Weather, customer behavior, economic conditions and other factors will have a significant influence on the parameters being measured under these metrics. As the Company begins to implement its grid modernization plan, the changes resulting from grid modernization may be subtle and difficult to detect. The use of baselines against which to measure ongoing performance will help develop an understanding of how the Company's grid modernization efforts are "moving the needle" in terms of progressing towards the achievement of the Department's Grid Modernization objectives.

The metrics use the following definitions for infrastructure metrics filings:

Grid Modernization Device - Any device that meets the requirements of either a fully automated or a partially automated device. This includes primary devices (breakers, reclosers, sectionalizers, switches, capacitor banks, voltage regulators, etc.) that are included in the grid modernization plan.

Fully Automated Device - Meets all of the following requirements:

- Reacts to system conditions to isolate or restore portions of the electric system;
- Communicates system quantities (e.g., voltage, trip counts) to a central location, such as SCADA; and
- The state of the device can be remotely controlled by dispatch.

Partially Automated Device – Meets at least one of following requirements:

- Reacts to system conditions to isolate or restore portions of the electric system;
- Communicates system quantities (e.g., voltage, trip counts) to a central location, such as SCADA;
- The state of the device can be remotely controlled by dispatch; or
  AND capable of upgrade to a fully automated device without full replacement.

Sensor – Equipment that records and sends information of the electric system that can be used to improve the efficiency or effectiveness of workforce or asset management (e.g., Fault locators that would help pinpoint a problem for more efficient crew deployment).

These proposed metrics will be broken down into 1) infrastructure metrics which tracks the implementation of grid modernization technologies and 2) performance metrics that measure progress towards the objectives of grid modernization. These metrics are designed to measure quantitative benefits associated with grid modernization benefits.

Metric	Grid Intelligence	Advanced Metering Systems	DERs	Planning and Forecasting	Enhanced Customer Services	Innovative Rate Desgn
Performance Metrics						
VVO Baseline	X					
VVO Energy Savings	X					
VV Peak Load Impact	X					
VVO Distribution Losses	X					
VVO Power Factor	X					
VVO Estimated GHG Impact	X					
VVO Related Voltage Complaints	X					
Number of customers on TOU Rates					X	X
Numer of customer enrolled in CEM services					X	X
Percent of meters providing interval metering		X				
Percent of System with Unbalanced Load Flow and Control Capabilities	X			X		
Control Functions Implemented by Circuit	X					
Number of Customers benefiting from Grid Mod investments	X	X	X	X		
Reliability Focused Grid Modernization Investments - Outage Duration	X					
Reliability Focused Grid Modernization Investments - Outage Frequency	X					
Inrastructure Metrics						
Grid Connected DG Facilities			X	X		
System Automation Saturation	X					
Numbers of Devices or Technoloies Deployed	X	X				
Associated Cost for Deployment	X	X	X	X	X	X
Reason for deviation between acutal and planned deployment	X	X	X	X	X	X
Projected deployment	X	X	X	X	X	X

Table 22: Proposed Performance Metrics

8.1 Performance Metrics – Baselines and Targets

The following performance metrics are designed to measure progress towards grid modernization. In some cases, the Company is able to provide baseline quantities for the proposed metrics. However, in some cases the baseline is not able to be provided without the installation of specific equipment used for measurement and verification.

8.1.1 Volt VAr Optimization (VVO) Baseline

8.1.1.1 Objective

Establish a baseline impact factor for each VVO enabled circuit which will be used to quantify the peak load, energy savings and greenhouse gas ("GHG") impact measures.

8.1.1.2 Assumptions

VVO dynamically controls and coordinates multiple devices to manage both voltage and reactive power. System-wide efficiency is achieved by simultaneously coordinating operations using continuous measurements from multiple sensors distributed across the circuit. Once a circuit has VVO enabled, a M&V process will be performed through operating VVO using a predetermined time period and series. Based on the results of this M&V process, a circuit level VVO impact and baseline will be created.

8.1.1.3 Calculation Approach

The following data will be tracked and reported on a substation and circuit basis:

a. Determine circuit loads through measurements during on/off periods
b. Apply temperature corrections.
c. Develop load profiles.

As part of the baseline data capture, each VVO circuit will capture hourly circuit data for real and reactive power.

8.1.1.4 Organization of Results

This information will be provided for each VVO enabled circuit and serve as the baseline variable for calculating demand reductions or serve as variables for other calculations, such as reductions in GHG emissions. This calculation will be performed once and will support both circuit and system level impacts.

8.1.1.5 Organization of Results

This information will be provided for each VVO enabled circuit and serve as the baseline variable for calculating demand reductions or serve as variables for other calculations. This will be performed annually, and support both circuit and system level impacts.

8.1.1.6 Baseline

The baseline will be calculated through measurement and verification after each circuit and/or substation is placed into service. The Company recommends that each VVO circuit will undergo an M&V process, the results of which will be used to estimate the impact the system has on system load. Baselines will be reported during the first annual report following the field measurement and verification.

8.1.1.7 Target

This is the baseline for the VVO metrics. Therefore a target is not appropriate for this metric.

8.1.2 VVO Energy Savings

8.1.2.1 Objective

Quantify the energy savings achieved by VVO using the baseline established for the circuit against the annual circuit load with the intent of optimizing system performance.

8.1.2.2 Assumptions

Once a circuit has VVO enabled, a measurement and verification process will be performed through operating VVO using a predetermined time period and series. Based on the results of this M&V process, a circuit level VVO impact and baseline will be created.

8.1.2.3 Calculation Approach

The following data will be tracked and reported upon on a substation and circuit basis:

a. Annual energy delivered in kilowatt hours (“kWh”) for the most recent three year time period prior to when the system is placed into service.

Energy Savings will be represented by the net impact of VVO using the baseline established for the circuit against the annual circuit load.

8.1.2.4 Organization of Results

This information will be provided for each VVO enabled circuit and serve as the baseline variable for calculating demand reductions or serve as variables for other calculations. This will be performed annually, and support both circuit and system level impacts.

8.1.2.5 Baseline

The baseline will be calculated through measurement and verification after each circuit and/or substation is placed into service. The measurement and verification process will require equipment and technology that the Company does not presently have installed. Baselines will be reported during the first annual report following the field measurement and verification.

8.1.2.6 Target

UES's benefit/cost model assumed a 2% reduction in energy consumption.

8.1.3 VVO Peak Load Impact

8.1.3.1 Objective

This metric is designed to quantify the peak demand impact VVO/CVR has on the system with the intent of optimizing system demand. This impact metric provides a peak load impact of VVO for selected circuits and peak periods.

8.1.3.2 Assumptions

For this metric, the Company will use active circuit M&V peak demand reduction results from individual circuits.

8.1.3.3 Calculation Approach

This metric will use the following data:

- Circuit level M&V estimated hourly demand reduction
- Circuit level hourly on/off VVO Status
- Circuit level hourly peak demand
- System Level yearly peak time

UES will apply the corresponding M&V estimated hourly demand reduction on all circuits with active VVO for the appropriate peak hour. As some circuits have different peak times, using the appropriate demand estimated reduction for the correct hour is important. This will result in a single (GW) estimated demand reduction attributed to VVO.

8.1.3.4 Organization of Results

The Company will provide individual circuit VVO performance, estimated demand reduction, as well as the summation of total system impact.

8.1.3.5 Baseline

The baseline will be calculated through measurement and verification after each circuit and/or substation is placed into service. The Company has the ability to measure peak demand on each circuit. However, in order to accurately develop a baseline, the peak demand will be measured during the measurement and verification process to eliminate any influence by customer load additions and reductions between now and when the VVO system is implemented on a given circuit. Baselines will be reported during the first annual report following the field measurement and verification.

8.1.3.6 Target
UES's benefit/cost model assumed a 2% reduction in peak demand.

8.1.4 VVO Distribution Losses

8.1.4.1 Objective
VVO reduces circuit demand by flattening and lowering circuit voltages, primarily by using voltage regulators. At the same time, VVO actively controls capacitor banks to maintain circuit power factors near unity. This distribution automation project will implement better voltage regulation to improve power quality and reduce losses. This includes the coordinated operation of a voltage regulator with a transformer load-tap changer at a substation.

Electrical loss in the circuit can be investigated using the difference between power provided by the circuit regulator and the total power delivered to the consumer loads. This impact metric presents the difference between circuit load measured at the substation via the SCADA system and the metered load measured through AMI.

8.1.4.2 Assumptions
There are many elements that contribute to differences between circuit load data and the hourly measurements. These factors include:

- Unmetered load, such as street lights
- Electricity theft
- Circuit line losses

8.1.4.3 Calculation Approach
Using hourly data for real and reactive power, one can determine hourly line losses. This represents both technical and non-technical, e.g., theft, losses.

8.1.4.4 Organization of Results
This information will be provided on an annual basis for VVO enabled circuits. Results will be based upon the results at the end of each calendar year.

8.1.4.5 Baseline
The baseline will be calculated through measurement and verification after each circuit and/or substation is placed into service. The measurement and verification process will require equipment and technology that the Company does not presently have installed. Baselines will be reported during the first annual report following the field measurement and verification.

8.1.4.6 Target
UES's benefit/cost model assumed a 2% reduction in peak demand and consumption. It is estimates that the line losses will be reduced by 2% as well.

8.1.5 VVO Power Factor

8.1.5.1 Objective

VVO reduces circuit demand by flattening and lowering circuit voltages, primarily by using voltage regulators. Simultaneously, VVO actively controls capacitor banks to maintain circuit power factors near unity. Power factor is an indication of how efficiently the distribution system is delivering power. A distribution system operating at unity power factor delivers real power more efficiently than one operating at either a leading or lagging power factor. This performance metric seeks to quantify the improvement that VVO is providing. However, power factor alone is not sufficient to accurately describe the impact VVO has on the system. At low demand levels, a poor power factor is not as significant as at high demand levels. Therefore, some qualifications must be made to accurately track power factor.

8.1.5.2 Assumptions

Performance will be based on circuit level hourly power quality measurements at the substation.

8.1.5.3 Calculation Approach

This metric will use the following data:

- Circuit level hourly Power Factor
- Circuit level hourly on/off VVO Status
- Circuit level hourly peak demand

For this performance metric, only power factors corresponding to greater than 75 percent of a circuit's peak annual demand will be used. This qualified data will then be averaged to provide a circuit by circuit power factor performance metric. These averages will then be used to generate a system power factor performance, weighted by the peak demand of each respective circuit.

8.1.5.4 Organization of Result

The results of this metric will be reported in a tabular format on a circuit by circuit basis and a total system tally. Power factor is a dimensionless metric.

8.1.5.5 Baseline

The baseline will be calculated through measurement and verification after each circuit and/or substation is placed into service. The measurement and verification process will require equipment and technology that the Company does not presently have installed. The baseline will be measured with VVO disabled and then again with VVO enabled to develop a baseline. The baseline for this metric will be reported in the first annual report after the measurement and verification is completed.

8.1.5.6 Target

UES has not developed circuit by circuit targets for this metric yet. However, the targets will be developed to operate the circuits as close to unity power factor as practicable.

8.1.6 VVO Estimated GHG Impact

8.1.6.1 Objective

This metric is designed to quantify the overall Greehouse Gas (GHG) impact VVO has on the system. A GHG reduction estimate will be derived from the circuit level energy savings.

8.1.6.2 Assumptions

For this metric, the Company will utilize active circuit M&V energy reduction results from individual circuits. No M&V results older than five years will be used. To calculate GHG reductions, the Company will use industry standard values for displaced GHG.

8.1.6.3 Calculation Approach

This metric will use the following data:

- Circuit level M&V estimated Energy Reduction
- Circuit level hourly on/off VVO Status
- Circuit level hourly energy
- Industry standard CO_2 Emissions Factor (Tons/MWhr)

UES will accumulate all hours with active VVO and use the respective M&V energy reduction estimate, applied against the hourly demand. This will result in a single Gigawhatt Hour (GWhr) estimated energy reduction attributed to VVO.

CO_2 avoided due to VVO will be calculated by multiplying the above energy reduction by a typical generation emissions factor based upon metric tons per MWh.

Formula: CO_2 Emissions (tons) = Energy Savings (MWhs) x CO_2 Emissions Factor (tons / MWh)

The calculation will use the GHG emissions factors consistent with those used in the most recent version Three-Year Energy Efficiency Plans.

8.1.6.4 Organization of Results

Each Company will provide individual circuit VVO performance, estimated energy reduction, as well as the summation of total system impact.

8.1.6.5 Baseline

The baseline will be calculated through measurement and verification after each circuit and/or substation is placed into service. The measurement and verification process will require equipment and technology that the Company does not presently have installed. Baselines will be reported during the first annual report following the field measurement and verification.

8.1.6.6 Target

The target for this will be to reduce GHG emissions by 2% in line with the 2% reduction in energy consumption and peak demand.

8.1.7 VVO Related Voltage Complaints

8.1.7.1 Objective

The primary focus of the VVO investments is to manage circuit voltages at a lower threshold while maintaining minimum voltage service requirements for all customers on a substation and circuit. Since VVO will be actively managing voltages, there is a desire to track and report on the potential for the introduction of VVO-related voltage complaints. While VVO is not an active solution in use by the Company today, there may be historical low voltage causes that exist outside of a customer's service connection and equipment. Certain voltage issues, such as those that are ultimately determined to have been caused by customer-owned equipment, will not be mitigated by the Company's VVO investments. The

8.1.7.2 Assumption

Prior to the requirement to track and report on whether VVO investments could potentially contribute to customer voltage complaints, there was never a need for the Company to track customer voltage complaints in this manner. In an effort to develop a baseline for this metric, the Company must manually review the available records to determine the cause and remedy of the voltage issue that led to the customer complaint.

Going forward, the Company intends to specifically track customer voltage complaints to determine if VVO investments led to the voltage condition giving rise to the customer complaint. The Company currently tracks customer voltage complaints in its Customer Information System ("CIS") and plans to revise the system coding to better capture the data necessary to determine if a voltage issue was impacted by VVO investments.

8.1.7.3 Calculation Approach

This metric will track and report on the following:

- Quantity of voltage complaints for the current year that are deemed caused by VVO voltage management by circuit for circuits that will have VVO installed.
- Three-year average of all voltage complaints by circuit covering the most recent three years
- Compare the current year quantity of voltage complaints with the three-year historic average

Formula: Voltage Complaint Baseline = AVERAGE ('Voltage Complaints Year N' +' Voltage Complaints N-1'+' Voltage Complaints N-2')

8.1.7.4 Organization of Results

The baseline voltage complaints and the annual VVO related voltage complaints (one VVO investments are active and enabled) will be provided on an annual basis for each circuit. Results will be based upon the results at the end of the calendar year. This will provide an opportunity to assess the effectiveness of the VVO investments while minimizing the introduction of new customer impact.

8.1.7.5 Baseline

Utilizing the assumptions discussed above, the Company will calculate the baseline to use to measure process under this metric.

8.1.7.6 Target

The goal of this metric is to minimize the quantity of voltage complaints related to VVO. At the present time, the Company does not have VVO so therefore no VVO related voltage complaints.

8.1.8 Number of Customers on TOU Rates

8.1.8.1 Objective

The objective of this metric is to measure the quantity of customers (by rate class) that are taking advantage of TOU rates. Increase in this metric is a measurement of the success of the TOU implemented by the Company.

8.1.8.2 Assumption

The assumption behind this metric is that a well-designed TOU rate that is transparent and understood by customers will lead to changes in customer behaviors and have a positive impact on the system.

8.1.8.3 Calculation Approach

UES will use its CIS system to identify the quantity of customers by rate class that are enrolled in TOU rates.

8.1.8.4 Organization of Results

The results will be based upon the end of the calendar year.

8.1.8.5 Baseline

UES does not currently has TOU rates in effect. More work will be required to determine appropriate baseline and targets.

8.1.8.6 Target

UES does not currently has TOU rates in effect. More work will be required to determine appropriate baseline and targets.

8.1.9 Number of Customers Enrolled in CEM Services

8.1.9.1 Objective

The objective of this metric is to measure the effectiveness of the Company's Customer Engagement Management project.

8.1.9.2 Assumption

The assumption behind this metric is that a well-designed customer interface to the Customer Engagement Management system that is transparent and understood by customers will lead to customers becoming more educated about their energy usage leading to educated decisions that benefit the customer and the grid.

8.1.9.3 Calculation Approach

UES will use its CIS system to identify the quantity of customers by rate class that are enrolled in TOU rates.

8.1.9.4 Organization of Results

The results will be based upon the end of the calendar year.

8.1.9.5 Baseline
UES does not currently have the CEM in place. More work will be required to determine appropriate baseline and targets.

8.1.9.6 Target
UES does not currently have the CEM in place. More work will be required to determine appropriate baseline and targets.

8.1.10 Percent of Meters Providing Interval Metering

8.1.10.1 Objective
The objective of this metric is to measure the Company's transition from its previous TS2 system to the PLX system that will provide for interval metering.

8.1.10.2 Assumption
The assumption behind this metric is that PLX metering will increase the opportunity for enhanced rate plans. As this number of PLX meters increases, the number of customers able to take advantage of these enhanced rate offerings should also increase.

8.1.10.3 Calculation Approach
UES will use its AMI system to identify the quantity of customers who have a PLX meter installed.

8.1.10.4 Organization of Results
The results will be based upon the end of the calendar year.

8.1.10.5 Baseline
At the end of 2020, the Company had 6,800 PLX meters installed.

8.1.10.6 Target
Any new meter installation will receive a PLX meter that is interval capable and any meter that is replaced will be with a PLX meter that is interval capable. This equates to approximately 2,500 interval capable meters being deployed annually.

8.1.11 Percent of System with Unbalanced Load Flow and Control Capabilities

8.1.11.1 Objective
This metric will demonstrate the progress in the ADMS investment by tracking the circuits that have been equipped with unbalanced load flow capabilities. This metric will support the objective of optimizing system performance and more specifically improve asset utilization, improve reliability and integrate distributed energy resources. ADMS gives system operators increased visibility on the real-time output of generating facilities. This metric is designed to demonstrate that the model is an accurate representation of field conditions.

8.1.11.2 Assumptions
A circuit will be assumed to have ADMS unbalanced load flow capability when all feeders are modeled daily with no unwarranted voltage or capacity violations.

8.1.11.3 Calculation Approach
This metric will track and report on the number circuits that have been successfully modeled (model conversion) within the ADMS system.

8.1.11.4 Organization of Results
This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year.

8.1.11.5 Baseline
The baseline for this metric will start at zero since no circuits have been modeled in ADMS yet.

8.1.11.6 Target
The target for this metric based upon the ADMS deployment schedule

8.1.12 Control Functions Implemented by Circuit

8.1.12.1 Objective
This metric will show the progress in the ADMS investment by tracking the control functions implemented at the circuit level. This metric will support the objective of optimizing system performance and more specifically minimize electrical losses and improve reliability.

8.1.12.2 Assumptions
A control function will be defined as the ability to automatically issue command to field devices based on real-time system condition (such as VVO or distribution automation), and a circuit will be included in this metric when all devices have met the grid modernization control capability as defined in the grid mod plan.

8.1.12.3 Calculation Approach
This metric will track and report on circuits with control function implemented. In addition, the Company will report on the number of customers on each feeder affected by this technology.

8.1.12.4 Organization of Results
This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year.

8.1.12.5 Baseline
The baseline for this metric will start at zero since the specific control functions laid out as part of the Company's plan have not been deployed.

8.1.12.6 Target
The target for this metric will be based on the ADMS deployment plan.

8.1.13 Numbers of Customers that benefit from Grid Mod Investments

8.1.13.1 Objective

This metric will show progress by tracking the numbers of customers who have benefitted from the installation of grid modernization devices. This metric will support the objective of optimizing system performance.

8.1.13.2 Assumptions

A customer will benefit from grid modernization investment when the planned grid modernization functionality has been installed on their circuit. For instance, if VVO is enabled on the circuit, all customers on the circuit will benefit from the investment.

8.1.13.3 Calculation Approach

This metric will track and report on the following:

Circuit number
Number of customers impacted (customers will only be counted once even if covered by multiple grid modernization investments.

8.1.13.4 Organization of Results

This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year.

8.1.13.5 Baseline

The baseline for this metric will start at zero since this will be tracking only the customers that benefit from Grid Modernization investments. A table with the type of device, circuit number where installed and number of customers benefitted will be provided to support the tracking of this metric.

8.1.13.6 Target

The baseline for this metric will be based on the ADMS deployment plan.

8.1.14 Reliability-Focused Grid Modernization Investments' Effect on Outage Durations

8.1.14.1 Objective

This metric will compare the experience of customers on circuits with the planned grid modernization investments as compared to the prior three-year average for the same circuit. This metric will provide insight into how grid modernization can reduce the duration of outages.

8.1.14.2 Assumptions

Outages and their impact are typically situational in nature. There are several project proposed with the benefit of improved reliability performance such as SCADA, AMI/OMS Integration and Mobile Damage Assessment. The circuit must have three years of SAIDI history to be included in the metric. Additionally, numerous factors, such as a Company's tree trimming cycle, weather and vehicular accidents, can impact system reliability, regardless of a Company's grid modernization investments.

8.1.14.3 Calculation Approach

This metric will track and report on the following:

- Circuit level SAIDI (CKAIDI) for circuits that have DA enabled in the GMP plan year
- Three-year average circuit level SAIDI covering the past three years

- Compare the current year circuit SAIDI with the three-year historic average SAIDI of the circuit

Formula: AVERAGE (‘CKAIDI Year N’+’ CKAIDI Year N-1’+’ CKAIDI Year N-2’) - ‘CKAIDI Year N’ = if greater than 0, positive impact.

8.1.14.4 Organization of Results

This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year.

8.1.14.5 Baseline

The metric will use the circuit three-year SAIDI average as the baseline. It will compare the SAIDI results of the plan year to the circuit’s three-year historic average.

8.1.14.6 Target

The target for this metric is to have the current year circuit level SAIDI (CKAIDI) to be less than the average of the CKAIDI of the preceding three years.

8.1.15 Reliability-Focused Grid Modernization Investments’ Effect on Outage Frequency

8.1.15.1 Objective

This metric will compare the experience of customers on circuits with the planned grid modernization investments as compared to the prior three-year average for the same circuit. This metric will provide insight into how grid modernization can reduce the duration of outages.

8.1.15.2 Assumptions

Outages and their impact are typically situational in nature. There are several project proposed with the benefit of improved reliability performance such as SCADA, AMI/OMS Integration and Mobile Damage Assessment. The circuit must have three years of SAIDI history to be included in the metric. Additionally, numerous factors, such as a Company’s tree trimming cycle, weather and vehicular accidents, can impact system reliability, regardless of a Company’s grid modernization investments.

8.1.15.3 Calculation Approach

This metric will track and report on the following:

- Circuit level SAIFI (CKAIFI) for circuits that have DA enabled in the GMP plan year
- Three-year average circuit level SAIFI covering the past three years
- Compare the current year circuit SAIFI with the three-year historic average SAIFI of that circuit

AVERAGE (‘CKAIFI Year N’+’ CKAIFI Year N-1’+’ CKAIFI Year N-2’) - ‘CKAIFI Year N’ = if greater than 0, positive impact.

8.1.15.4 Organization of Results

This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year.

8.1.15.5 Baseline

The metric will use the circuit three-year SAIFI average as the baseline for this metric. It will compare the SAIFI results of the GMP plan year to that three-year historic average.

8.1.15.6 Target

The target for this metric is to have the current year circuit level SAIFI (CKAIFI) to be less than the average of the CKAIFI of the preceding three years. At this point the plan does not call for projects designed to affect SAIFI, so this metric will be included if and when projects designed to affect SAIFI are proposed.

8.2 Infrastructure Metrics

The following infrastructure metrics are designed to measure progress towards grid modernization plan. In some cases, the Company is able to provide baseline quantities for the proposed metrics. However, in some cases the baseline is not able to be provided without the installation of specific equipment used for measurement and verification.

8.2.1 Grid Connected Distribution Generation Facilities

8.2.1.1 Objective

One of the primary objectives of grid modernization is to facilitate the interconnection of DERs and to integrate these resources into the Company's planning and operations processes. This infrastructure metric will quantify the DER units connected to the system on a circuit level and substation level basis. It is important to note that DER developer decisions regarding DER interconnection may be influenced by tax incentives, subsidies, costs, and availability of the technology, which, in turn, will influence these metrics.

8.2.1.2 Assumptions

The data used in these calculations consider units that have an executed Interconnection Service Agreement ("ISA") and are in service and connected to the distribution system.

8.2.1.3 Calculation Approach

The following data will be tracked and reported upon on a substation and circuit basis:

a. Total number by technology or fuel type – count of units by technology or fuel type
b. Nameplate capacity by technology or fuel type – sum total of nameplate capacity
c. Estimated output by technology or fuel type – sum of nameplate capacity * capacity factor * 8760 hours
d. Type of customer-owned or operated units by technology and fuel type – (i.e., count of Photo Voltaic ("PV"), wind, Combined Heat and Power ("CHP"), Fuel Cell, etc.)
e. Nameplate as a Percent of Peak Load – calculated as total nameplate capacity (MW) / peak load (MW).

8.2.1.4 Organization of Results

This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year. This metric is a study of the overall quantity and capacity of grid connected distributed generation facilities. Data will be provided in a tabular basis.

8.2.1.5 Baseline

The baseline for this metric are quantified and calculated based upon units in service by December 31, 2020.

The baseline quantities will include the following:

a. Total number by technology or fuel type – count of units by technology or fuel type
b. Nameplate capacity by technology or fuel type – sum total of nameplate capacity

c. Estimated output by technology or fuel type – sum of nameplate capacity * capacity factor * 8760 hours
d. Type of customer-owned or operated units by technology and fuel type – (i.e. count of PV, wind, CHP, Fuel Cell, etc.)
e. Nameplate as a Percent of Peak Load – calculated as total nameplate capacity (MW) / peak load (MW)

8.2.1.6 Target

UES is still evaluating the targets. These metrics are highly influenced by factors outside of the control of the Company.

8.2.2 System Automation Saturation

8.2.2.1 Objective

This metric measures the quantity of customers served by fully automated or partially automated device. The terms "fully automated" and "partially automated" refer to feeders for which the Company has attained full or partial, respectively, levels of visibility, command and control, and self-healing capability through the use of automation.

8.2.2.2 Assumptions

Baseline saturation rate will be calculated based on what exists on the system as of the December 31, 2020. Ideally over time this metric will decrease based on GMP installed devices since the metric is calculating the number of customers per device installed. As more devices are installed the metric decreases. Customers that can benefit from multiple devices will be counted as one for purposes of calculating the baseline. The installations will not be limited to the main line infrastructure and will include no-load lines and DSS lines.

8.2.2.3 Classification of Grid Modernization Devices

The following matrix has been provided as guidance to determine which type of equipment would be considered partially automated, fully automated or included as a sensor.

Device Type	Not Included	Partial Automation	Full Automation	Included as a Sensor
Feeder Breakers (No SCADA)		X		
Feeder Breakers (SCADA)			X	X
Reclosers (including sectionalizers, single phase reclosers, intellirupters, ASU) (No SCADA)		X		
Reclosers (including sectionalizers, single phase reclosers, intellirupters, ASU) (SCADA)			X	X
Feeder Meter (e.g., ION, with SCADA)				X
Capacitor and Regulator with SCADA		X		X
Capacitor and Regulator no SCADA	X			
Line Sensor (with SCADA)				X
Fault Indicator (with SCADA)				X
Other Fault Indicators (no SCADA)	X			
Customer Meter	X			
Distribution / step down Transformer	X			
Other Substation Breakers	X			
Fuse	X			

Table 23: Classification of Grid Mod Devices

8.2.2.4 Calculation Approach

As more automation is installed pursuant to the plan, the results of this metric will be reduced.

Formula:

$$\frac{\text{Customers Served on Circuit}}{\text{Fully Automated Device} + 0.5*(\text{Partially Automated Device})}$$

8.2.2.5 Baseline

The baseline for this metric will be quantified and calculated based upon equipment in service as of December 31, 2020. Ideally over time this metric will decrease based on GMP installed devices. Customers that can benefit from multiple devices will be counted as 1. Customers that do not benefit from a grid modernization investment are counted as zero.

Calculation:

$$\frac{\text{Customers Served}}{\text{Fully Automated Device} + 0.5*(\text{Partially Automated Device})}$$

8.2.2.6 Target

The target for this metric is still under development.

8.2.3 Number of Devices or Technologies Deployed

8.2.3.1 Objective

These metric measures how the Company is progressing with its plan from an equipment and/or device standpoint.

8.2.3.2 Assumptions

The number of devices for each investment will need to be determined and/or updated from the initial GMP. The number of devices installed will be compared to the total number of devices planned by circuit for each investment.

8.2.3.3 Calculation Approach

The following information will be tracked and reported upon per investment at the substation and circuit level where appropriate:

a. Number of devices or other technologies deployed
b. Total number of devices planned
c. Percent – Number of devices installed / total number of devices planned

8.2.3.4 Organization of Results

This information will be provided on an annual basis. Data will be based upon the results at the end of the calendar year. The metrics will be reported upon at the substation and circuit level where appropriate.

8.2.3.5 Baseline

UES has not completed the detailed design work necessary to determine the total number of devices planned for a given project. The detailed design work is underway and the baseline will be reported in the first annual filing.

a. Number of devices or other technologies deployed
b. Total number of devices planned
c. Percent – Number of devices installed / total number of devices planned

8.2.3.6 Target

The target for this metric has not been finalized as of yet.

8.2.4 Associated Cost for Deployment

8.2.4.1 Objective

This metric measures the associated costs for the number of devices or technologies installed and is designed to measure how the Company is progressing.

8.2.4.2 Assumptions

The cost of devices or technologies for each investment will need to be determined and/or updated from the initial GMP. The cost of devices installed will be compared to the total cost of devices planned by circuit for each investment.

8.2.4.3 Calculation Approach

The following information will be tracked and reported upon per investment at the substation and circuit level where appropriate:

a. Cost of devices or other technologies deployed
b. Total cost of devices planned
c. Percent – Cost of devices installed / total cost of devices planned

8.2.4.4 Organization of Results

This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year. The metrics will be reported upon at the substation and circuit level where appropriate.

8.2.4.5 Baseline

UES has not completed the detailed design work necessary to determine the total number of devices planned for a given project. The detailed design work is underway and the baseline will be reported in the first annual filing.

a. Cost of devices or other technologies deployed
b. Total cost of devices planned
c. Percent – Cost of devices installed / total cost of devices planned

8.2.4.6 Target

The target for this metric is still under development.

8.2.5 Reasons for Deviation between Actual and Planned Deployment for the Plan Year

8.2.5.1 Objective

This metric is designed to measure how the Company is progressing under its plan on a year-by-year basis.

8.2.5.2 Assumptions

The quantity and cost of devices or technology for each investment will need to be determined and/or updated from the initial plan on a year-by-year basis. The quantity and cost of devices or technology installed in a given investment year will be compared on a year-by-year basis and any variations will be quantified and addressed.

8.2.5.3 Calculation Approach

The following information will be tracked and reported upon per investment at the substation and circuit level where appropriate:

a. Number of devices or technology installed versus plan for a given year
b. Cost of devices or technologies installed versus plan for a given year
c. Reason for discrepancies

8.2.5.4 Organization of Results

This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year. The metric will be reported at the substation and circuit level where appropriate.

8.2.5.5 Baseline

The baselines required to complete the quantification and calculation for this metric will be provided.

a. Number of devices or technology installed versus plan for a given year
b. Cost of devices or technologies installed versus plan for a given year
c. Reason for discrepancies

8.2.5.6 Target

The targets required to complete the quantification and calculation for this metric will be provided.

8.2.6 Projected Deployment for the Remainder of the Three Year Term

8.2.6.1 Objective

This metric is designed to measure how the Company is progressing under its plan on a year-by-year basis. This will be used for the following year comparison of the plan versus the actual implementation completed in the following year.

8.2.6.2 Assumptions

The year-by-year investment plan is subject to change based upon the quantity of work completed, the availability of the technology, material lead times, contractor availability, etc. The revised investment plan each year will be used as the basis of comparison for the following year's work.

8.2.6.3 Calculation Approach

The following information will be tracked and reported upon per investment at the substation and circuit level where appropriate:

a. Number of devices or technology to be installed the following year
b. Cost of devices or technologies installed the following year

8.2.6.4 Organization of Results

This information will be provided on an annual basis. Results will be based upon the results at the end of the calendar year. The metric will be reported upon at the substation and circuit level where appropriate.

8.2.6.5 Baseline

The metric will be used as the baseline and target for the following year's work and will be reported on an annual basis.

a. Number of devices or technology to be installed the following year
b. Cost of devices or technologies installed the following year

8.2.6.6 Target

The metric will be used as the baseline and target for the following year work and will be reported on an annual basis.

9 ANNUAL REPORTING

UES proposes to continue to follow the filing requirements for the LCIRP plan which is proposed to be filed every three years. The Company will continue to work with the Commission and the stakeholders to finalize the requirements of the LCIRP filing.

In addition, the Company is also proposing to file the following information on an annual basis. Annual reporting would take place on years in between the LCIRP filings.

- Most recent distribution and system level planning studies
- Distribution and system level load forecasts including a comparison of its ten year historic load with the prior year's 90/10 projection. Forecast should take into consideration DER and EVs.
- Circuit level and substation level load forecast in comparison to circuit or substation capacity limits
- Identification of capacity constraints and alternatives reviewed (NWA and traditional investments)
- NWA analysis for all projects in excess of $250,000
- A summary of stakeholder input, how stakeholder recommendations are incorporated into the final plan, or why a stakeholder recommendation was not incorporated into the final plan
- DG Interconnections by circuit and by type of prime mover
- Discussion of progress on grid modernization projects including reasons for deviation from the prior year's plan
- Performance and infrastructure metrics

10 STAKEHOLDER ENGAGEMENT

The Company's vision of advancing the grid is to develop and enabling platform that serves all customers and users of the system. Stakeholder engagement is designed to improve the overall transparency of the grid modernization planning process. Stakeholder engagement is an important aspect to determining the functionality desired in the advanced grid. This plan is a living document and will be flexible enough to adjust to the changing requirements of the system. This plan is a starting point. Stakeholder input is now required to adjust the course to provide the most benefit to the system and its customers.

UES has worked closely with the stakeholder group during the LCIRP, data sharing, locational value of DG, energy efficiency, value of solar and various other dockets. The Company proposes to use the process developed as part of the LCIRP docket as a means to solicit input and needs with respect to grid modernization investments.

UES proposes to meet with stakeholders during the development of the LCIRP plan. The goal of the stakeholder process is to allow meaningful opportunities for input on decisions affecting utility planning and related investments and lead to more uniform, more transparent, and more successful modernization of the grid and will have the benefit of reducing the amount of litigation necessary to review and approve.

UES will follow the stakeholder process that is required in conjunction with the LCIRP filing. However, if a stakeholder process is not detailed, the Company proposes to use the following process:

> Meeting 1: Pre-Planning Meeting – The goal of this meeting is for the stakeholder to provide some initial feedback to the Company prior to plan development, review of previous plan and any changes to assumptions.
>
> Meeting 2: Project Identification and Consideration – the Company presents preliminary findings as a result of the planning process. Stakeholders have the opportunity to provide input to the proposed alternatives and project priorities.
>
> Meeting 3: Project Plan – the Company presents the proposed plan and seeks any final input.

Ultimately, the Company is responsible for the safe and reliable operation of the electric distribution system at a reasonable cost. Any alternatives considered should have an equivalent capacity, reliability, availability and life span of the competing options. The Company is confident that this approach will increase the transparency of the planning process to the stakeholder group.

11 CYBER SECURITY, PRIVACY AND DATA ACCESS

UES views this planning process and the implementation of the plan as an opportunity for continued improvement of its cybersecurity program to meet its evolving security and compliance needs over the next ten years.

The following paragraphs describe the cybersecurity processes and procedures that the Company has adopted to prevent unauthorized access to control systems, operations, and data in accordance with existing and emerging best practices, national standards, and state and federal laws. These processes will be incorporated into future program capabilities as a framework for the further enhancement of the program.

11.1 Cyber Security Governance

11.1.1 Executive Oversight & Reporting

The Vice President of Information Technology and Chief Information Security Officer (CISO) who reports to the Executive leadership and has overall responsibility for cyber security at the Company oversees the current cyber security program. The CISO reports quarterly to the Executive leadership on the status of cybersecurity as well as other matters of significance in this area. The CISO has responsibility of proper reporting both internally and externally of cybersecurity events when they occur.

11.1.2 Application Owners

As per the Company's Written Information Security Plan (WISP) and current policies, system Application Owners (AOs) are responsible for working with the IT Department on any issues and technical problems including identified security issues or concerns. The Company periodically participates in Business Impact Analysis (BIA) where business units conduct tabletop exercises of various scenarios including cyber security events to determine overall risks to the organization as well as practical measures to mitigate risks of high impact and/or probability. The Company also participates in NERC's GridEx North America grid security exercise, where remediation exercises are vetted and potential gaps are identified.

11.1.3 Operating Model

The Information Technology Department has overall responsibility for cyber security. For new projects, IT is involved in the beginning of the process and is engaged to determine the best practices for implementation from a cybersecurity perspective. Cyber security will be a critical component of all GMP projects.

11.1.4 Risk Management

UES participates in annual Risk Management Exercises with senior managers and Executive staff where risks to company operations are identified. Their potential impact and likelihood are assessed. Appropriate mitigation measures are determined and implemented as appropriate in applicable areas of the organization. The IT department closely monitors resources such as E-ISAC, and Industrial Control Systems Cyber Emergency Response Team (ICS-CERT) for current cybersecurity risk identification.

11.1.5 Policy Development & Deployment

Policies and other procedural controls are implemented as the result of industry best practice, past experience, information garnered from internet sources, and research through professional organizations.

11.1.6 Standards Development & Sustainment

Standards at the Company are largely derived from published standards adapted to meet the Company's specific circumstances. Experiential knowledge, joint exercises with other entities, outside consultants, and independent research with on-line resources are the basis for most of the standards in place.

11.2 Cybersecurity Asset Management & Protection

11.2.1 Cyber Control Framework

UES maintains the WISP and related policies for the maintenance and protection of cyber assets. The WISP and related policies detail processes and procedures for the management of assets, security of systems, and maintenance of Personally Identifiable Information (PII) privacy.

11.3 Cybersecurity IT & OT Technical Controls

11.3.1 Standards & Control Implementation

The WISP details controls and standards for the securing of systems and handling of PII. Details such as password requirements, access control for PII, and protection controls for data are enumerated in the document. The WISP is supported by other polices such as Asset Management, Backup and Recovery, Change Management, and Security Administration to define the cyber security posture.

11.3.2 Security Planning & Architecture

The overall security environment is designed around the corporate network perimeter shielding or segregating the more sensitive ADMS, SCADA and control environments. Operational control networks, such as ADMS and SCADA are isolated.

11.3.3 Intrusion & Threat Detection

The Company employs Intrusion Detection and other threat detection tools within its network environments. Systems and networks are monitored for anomalous events with automatic notifications to appropriate personnel. The Company also completes penetration tests to evaluate the security of its network and modifies security protocols when risks are identified.

11.3.4 Incident & Event Management

The WISP details the response plan for the investigation and subsequent reporting in the event of a suspected security breach.

11.3.5 Vulnerability Assessment

The Company actively assesses cyber security vulnerabilities with internal and external expertise. Assessment methods include external penetration tests, compliance review against standards, industry collaboration, and monitoring of online resources. The Company evaluates vulnerabilities for their potential impact to the Company and prioritizes for remediation through additional technical, operational, or physical controls.

11.4 Readiness Verification

11.4.1 Program Capability Assessment

UES reviews its cyber security program against published industry standards to assess maturity level and to identify weaknesses or areas for improvement.

11.4.2 Compliance Assessment

UES participates in NERC Critical Infrastructure Protection (CIP) audits for its divisions. To date, no violations, no potential violations, and no recommendations have been received. The Company assesses NERC CIP compliance against all GMP activities. The Company engages an outside entity for Payment Card Industry (PCI) compliance and testing activities.

11.5 Incident / Event Investigations

The Manager, Cyber Security and Compliance is responsible for conducting the investigation of suspected breaches at the Company.

11.6 Risk and Threat Management and Reporting

11.6.1 Assessment & Ranking of Threats & Risks

Threat information from outside sources and log activity is evaluated for its potential impact to the Company. Threats are prioritized for remediation through additional technical, operational, or physical controls.

11.6.2 Compliance Reporting

Unitil has established processes for the reporting of incidents related to NERC CIP and/or PCI compliance.

11.6.3 Report Compilation

Report compilation for the data security and privacy events is the responsibility of the Manager, Cyber Security and Compliance. The Manager, Cyber Security and Compliance acts as custodian of compliance reports according to the Company's data retention policy.

12 Summary

The traditional grid as we know it has developed over the past 100 years based upon the individual design characteristics and customer needs. This has been a methodical approach providing our customers with safe and reliable electric service at a reasonable cost. Technology innovation and customer's desire to take control of their own energy usages is changing this paradigm.

As customers adopt new technologies, and as distributed energy resources are increasingly connected to the distribution system, the fundamental architecture of the electricity delivery system (the "grid") must change. The 20th Century electric grid, originally designed to distribute power from large centralized generating plants, must now integrate a wide array of distributed load, storage and generation resources. A grid that was designed for "one way" power flow must now accommodate two-way power flow, increasing the need for sophisticated protection, communication, metering, and intelligence. The grid must also provide opportunities for customers to understand and actively participate in energy markets to enhance efficient utilization and consumption of electricity, while delivering improved reliability and power quality.

This plan represents "foundational" grid modernization investments. This plan describes the Company's vision of the advanced grid as and enabling platform that allows and encourages new and different use cases. These use cases cannot be supported without some technology building blocks that will provide the ability for increased grid intelligence and data sharing. The foundational grid modernization investments proposed in this plan address the objectives of 1) Environmentally Friendly, 2) Safety and Reliability, 3) Customer Service, 4) Security, 5) Flexibility, 6) Affordability, 7) Demand and Asset Optimization and 8) Technology Innovation.

The projects identified in this plan are "foundational" grid modernization projects. The table below summaries the projects and the spending plan over the next 10 years.

Projects	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Field Area Network	$ 90	$ 56	$ 127	$ 626	$ 325	$ 463	$ 780	$ 811	$ 640	$ 704	$ 4,622
ADMS and DERMS	$ 668	$ 468	$ 378	$ 298	$ 170	$ -	$ -	$ -	$ -	$ -	$ 1,981
Volt/VAR Optimization	$ -	$ 383	$ 2,000	$ 2,929	$ 2,731	$ 2,862	$ 2,880	$ 3,416	$ 3,488	$ 4,292	$ 24,981
SCADA	$ -	$ 1,530	$ 1,740	$ 760	$ 790	$ 250	$ 340	$ 420	$ 550	$ 760	$ 7,140
Mobile Damage Assessment	$ 449	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 449
AMI/OMS Integration	$ 107	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 107
Data Sharing Platform	$ 449	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 449
Total	$1,763	$2,437	$4,245	$4,612	$4,016	$3,575	$4,000	$4,647	$4,678	$5,756	$ 39,729

Table 24: Foundational Grid Modernization Investments

This plan is a starting point of a long journey towards an advanced grid that provides customers with the ability to maximize the benefits of their investments. It defines some critical foundational grid modernization investments that are required to develop the grid into an enabling platform. Metrics, annual reporting and stakeholder engagement processes have been proposed to provide transparency in grid modernization planning. This plan is not designed to take the place of the LCIRP process. Instead the Company recognizes that LCIRP is designed to identify the geographical investments focused on alleviating locational constraints of the system. However, these foundational investments are required to maximize the value of the geographical investments.

APPENDIX A

MAPPING CATEGORIES AND PROJECTS/FUNCTIONALITIES TO OBJECTIVES

Category	Project/Functionality	Existing / Planned	Safety and Reliability	Customer Enablement	Security	Flexibility	Affordability	Demand and Asset Optimization	Technical Innovation	Environmentally Friendly
Grid Intelligence	Advanced Distribution Management System (ADMS)	Planned	X	X	X	X	X	X	X	X
	Distributed Energy Resources Management System (DERMS)	Planned	X	X	X	X	X	X	X	X
	Outage Management System (OMS)	Existing	X	X					X	
	Supervisory Control and Data Acquisition (SCADA)	Existing	X	X	X	X	X	X	X	X
	Volt/Var Optimization	Planned	X	X		X	X	X	X	X
	OMS/AMI Integration	Planned	X	X					X	
	Advanced Field Communications (FAN/WAN)	Planned	X	X	X	X	X	X	X	X
Advanced Metering	Advanced Metering Infrastructure (AMI)	Existing		X		X	X	X	X	X
	Interval Metering	Existing		X		X	X	X	X	X
	Meter Data Mangement System	Existing		X		X	X	X	X	X
Distributed Energy Resources	Generator Interconnections	Existing	X	X		X	X	X	X	X
	Solar Way 1.3MW	Existing	X					X		X
	Townsend Energy Storage	Planned	X	X		X	X	X	X	X
	Smart Inverters	Planned	X	X		X	X	X	X	X
	Electric Vehicles	Planned	X	X		X	X	X	X	X
	Demand Response Program	Existing	X	X		X	X	X	X	X
	Energy Efficiency	Existing	X	X		X	X	X	X	X
Advaced System Planning and Forecasting	Geospatial Information System	Existing	X			X			X	
	DER Forecasting	Existing	X	X		X	X	X	X	X
	Electrification Forecasting (EV and Heat Pumps)	Existing	X	X		X	X	X	X	X
	Hosting Capacity Analysis	Planned	X	X		X	X	X	X	X
	Locational Value Analysis	Planned	X	X		X	X	X	X	X
Enhanced Customer Servcies	Digitizing Core Services	Planned		X		X	X		X	
	Optimizing the Customer Life Cycle	Planned		X		X	X		X	
	Extending the Value-Add	Planned		X		X	X	X	X	X
	Providing Total Energy Solution	Planned		X		X	X	X	X	X
Innovative Rate Design	Residential/Business TOU	Planned	X	X			X	X	X	X
	EV TOU	Planned	X	X			X	X	X	X
	Distributed Energy Resources	Planned	X	X			X	X	X	X
	Behind the Meter Partnerships	Planned	X	X			X	X	X	X
	Make Ready Programs	Planned	X	X			X	X	X	X

APPENDIX B

Advanced Distribution Management System

Distributed Energy Resource Management System

Project Description

Advanced Distribution Management System

Project Description

December 22, 2020

Prepared By:
Jake Dusling
Unitil
6 Liberty Lane West
Hampton, NH 03842

Table of Contents

1 Introduction

As part of the Company's Grid Modernization Plan for Fitchburg Gas and Electric, Unitil is in the process of implementing an Advanced Distribution Management System (ADMS) throughout its electric service territory in Massachusetts (FG&E). Given the nature of the systems and its integration with other systems Unitil has elected to implement ADMS for its New Hampshire service territories (UES) as well. The level and schedule of deployment will differ in FG&E and UES.

An ADMS is the next step in the evolution of distribution management systems. An ADMS integrates a comprehensive set of monitoring, analysis, control, planning, and informational tools that work together with one common network model. An ADMS merges existing OMS, ADMS, unbalanced load, short circuit analysis and SCADA systems together to provide a real-time view of the distribution system.

An ADMS system can provide many different functions such as (but not limited to) self-healing automation, control for distributed energy resources, additional SCADA functions across the distribution system, real-time load flow and circuit analysis, demand response, outage restoration, direct load control and network configuration. Additionally the Company's ADMS will utilize "real-time" unbalanced load flow calculation results to automatically control distribution equipment for VVO.

2 ADMS Request for Proposal Process

Throughout 2019 Unitil developed and issued a Request for Proposal (RFP) to five qualified bidders. After a multi-step evaluation process Unitil partnered with ABB/Siena to update its existing OMS to an ADMS.

For additional information on the RFP process including the evaluation of proposals reference the Company's Advanced Distribution Management System – Recommendation for Award document.

3 Initial Corporate ADMS Deployment

Unitil's initial ADMS deployment will require new and enhanced integrations to various Unitil systems and the additional modelling of the Company's electric system in ABB's Network Manager system (ABB's ADMS platform). This will require Unitil to design and build a new secure IT network for the ADMS platform. Once complete the Company's entire electric system will be modelled in ADMS and capable of utilizing the ADMS functions described below.

ADMS Functionalities

3.1.1 Unbalanced Loadflow

The ADMS will have the ability to perform unbalanced loadflow simulations on the Unitil distribution system. Loadflow simulations will be automatically run by ADMS on a circuit by circuit basis after system changes are made or a predefined time after the previous simulations were performed for circuits that have SCADA telemetry data available in ADMS. Circuit without real-time SCADA information will have the ability to be run at an ad hoc basis utilizing user defined load levels. Simulations will also have the ability to be run manually by ADMS operators/users.

The loadflow models will have the ability to be run using current load levels as well as historical and future anticipated load levels. Loadflow results will "flag" potential voltage and loading violations as well as recommend switching steps that could be performed to mitigate the identified violations.

The loadflow models will also be utilized as the basis for many of the capabilities described below.

3.1.2 VVO

Unitil's Corporate ADMS deployment will include the integrations and testing necessary to be "VVO ready". This will include the deployment of VVO on select circuits in the FG&E territory to confirm VVO operates as designed. Remaining VVO deployment will be included in DOC specific VVO deployment projects.

Unitil is planning to deploy model based VVO algorithms with measurement verification. ADMS will automatically control LTCs, regulators and capacitor banks based on "real-time" unbalanced loadflow results to operate the system at the lower end of the acceptable voltage range to reduce electric demand and energy consumption. The Company's ADMS is capable of performing measurement based VVO algorithms when the necessary field data becomes available.

3.1.3 Fault Location

The ADMS will have the ability to perform fault location calculations based on the status of remote devices and sensors. The system will also have the ability to utilize fault current and target information from relays (either automatically provided via SCADA or that is manually entered by a system operator) and perform short circuit calculations to estimate fault location(s) with and without the status of other devices.

3.1.4 Automatic Restoration Schemes and FLISR

Unitil's Corporate ADMS deployment will include the migration of existing distribution automation schemes to ADMS. This will allow existing schemes to be enhanced and in some cases be utilized more often and to provide additional reliability benefit. It will also give Unitil to the experience of implementing automation schemes in ADMS and allow Unitil to confirm the functionality of automatic restoration schemes in ADMS.

ADMS integration of new automatic restoration schemes will be included in DOC specific projects.

ADMS will also monitor SCADA device status and recommend system switching to restore as much load as possible prior to repairs being made.

3.1.5 System Monitoring/Alarming

ADMS will perform "real-time" monitoring of the Company's subtransmission, substation and distribution systems. ADMS will alarm and provide recommended courses of actions for the following:

- Loading above predefined thresholds
- Voltages above or below predefined thresholds
- Power factor outside of predefined thresholds
- Operation of system devices

3.1.6 Switch Order Module

ADMS will be utilized as the Company's switching order management system. It will have the ability to create switching orders in a test/simulation environment by the user mimicking the proposed switching. Users will also have the ability to manually add steps to switching orders that may not be directly executable in ADMS.

ADMS will have a method for routing the switching orders to necessary parties for approval and once approved the switching orders shall be available in the "live" ADMS environment for execution.

Additionally, ADMS will have the ability to recommend switching (utilizing both remote control and manually controlled devices) based on the following:

- Fault location data and calculations to restore as many customers as possible during an outage situation.
- Future planned equipment to be out of service.
- Contingency analysis following planned or unplanned outages.

Unitil plans to require operator intervention for most ADMS switching functionality. ADMS will have the configurability to allow the user to step through and execute each switching step independently or execute portions or the entire switch order at once.

3.1.7 System Power Factor Management

Unitil plans to utilize ADMS to manage overall system (transmission tie point) power factor for compliance with ISO-NE load power factor requirements. This management will require ADMS to monitor system power factor and recommend capacitor switching (automatically switch in the future) of substation and subtransmission capacitor banks to maintain a system power factor that is compliant with ISO-NE requirements. In the event the necessary system power factor cannot be achieved with subtransmission and substation capacitor banks the system power factor management shall override VVO and utilize distribution capacitor banks as needed.

The system will be capable of managing different power factor requirements for FG&E and UES.

3.1.8 Manual Load Shed

Unitil plans to utilize ADMS to manage the Company's ISO-NE manual load shed process. This management requires ADMS to monitor system and circuit loads and recommend circuits to de-energize based on real-time loading to meet a specified percent of system load to shed. This functionality will also take into account critical loads. For simulated load shed tests the system will report the "pre-load shed" system load as well as the anticipated "post-load shed" system load. In the event an actual load shed event is needed the user will be able to run the simulation, confirm results, create the switching order and then transfer the switching order to the "live" environment for execution.

The system will be capable of managing different load shed requirements for FG&E and UES.

3.1.9 Simulation Mode

The ADMS will have the ability to run all functionalities in "simulation" mode within the "production" environment and have the ability to run "what if" scenarios at past and future load levels.

Scenarios evaluated in simulation mode will have the ability to be routed and approved if necessary and be transferred out of simulation mode for future execution by an operator in the "live" ADMS environment.

3.1.10 Test/Training Environment

ADMS will have two discreet environments one for "production" and one for "testing/training". ADMS will have the ability to run all functionalities in the "test/training" environment. This environment is intended to be used when training employees on the use of ADMS, testing new functionalities of ADMS prior implementing in the "production" environment and during company-wide electric storm drills.

The “test/training” environment will be separate from the ADMS “production” environment such that any changes or scenarios implemented in the “test/training” environment will not be transferrable to the “production” environment.

The “test/training” environment will have the ability to be pre-loaded with historical and fictional scenarios to simulate day-to-day operation or major storm scenarios.

3.1.11 ADMS Data Archiving

The ADMS will have the capability to archive system and device statuses for future evaluation and use. At the minimum the following archiving requirements are required:

- System loads, system power factor, equipment loading and device status at pre-determined time intervals (e.g. every hour)
- The data and time a device changes state
- Switching orders with the time stamp for each step
- Ability to save simulations / ”what-if” scenarios

ADMS Integrations

In order to perform all the required functionality of ADMS integrations with the following systems will need to be enhanced or created.

3.1.12 GIS

The existing integration between GIS and OMS will be enhanced to provide ADMS with the necessary circuit topology, connectivity information and technical data (equipment rating, impedances, etc.) required to perform unbalanced loadflow and circuit analysis.

This will require the population of technical data and modifications to how many types of equipment are modelled in GIS as well as enhancements to the GIS to OMS/ADMS conversion process. This will also require the detailed modelling of substation and subtransmission equipment in GIS.

This will also require Siena to develop a symmetrical component calculation algorithm that will utilize GIS technical data (conductor impedance data and construction configuration) and line segment length to calculate and assign sequence impedances to line segments for use in short circuit analysis.

Additionally, due to the “real-time” nature of ADMS Unitil will need to develop new internal workflows to allow GIS to be updated as system modifications are placed in service and not lag behind equipment being installed in the field.

3.1.13 SCADA

When Unitil awarded the ADMS project to ABB it was planned that the Company’s existing ACS SCADA master would be integrated with ADMS utilizing an ICCP interface.

Early in the ADMS implementation process it become apparent that integrating the existing ACS SCADA master with ADMS would create usability concerns, future maintenance challenges and additional ongoing costs. After careful consideration and evaluation it was determined that Unitil will transition from its current ACS SCADA master to the ABB SCADA master.

This transition will include the establishment of the ABB SCADA historian that will archive SCADA data. Siena will also create customized SCADA reports that will allow for the simplified querying of SCADA data and provide it in a format that is easily usable by Unitil personal.

Additional information regarding the decision to transition to the ABB SCADA master can be found in the Company's Advanced Distribution Management System – Recommendation to Transition to ABB SCADA.

As was the case with GIS, Unitil will need to develop new internal workflows to allow SCADA to be updated as system modifications are placed in service and not lag behind equipment being installed in the field.

3.1.14 Net Meter Photovoltaic Output Estimation

Unitil will be developing a method for ADMS to estimate the "real-time" output of net metered photovoltaic (PV) generation output. This will be done by determining a calculated relationship/factor between "large-scale" PV that has real-time SCADA telemetry and net metered PV.

Siena will utilize this relationship/factor to develop an algorithm that will assign "real-time" generation output to net metered PV utilizing large DG SCADA telemetry and nameplate DG capacity.

3.1.15 Metering System(s)

Unitil will be developing a new integration between the Company's metering system and ADMS. This integration will provide ADMS metering information for each customer on the system that will be utilized along with SCADA information to calculate assumed "real-time" customer consumption and generation output.

Additional information on this integration can be found in the Company's Electric Customer Profiles for ADMS – SOW.

3.1.16 Siena Reports

Siena has developed several custom reports to allow Unitil to easily query reliability data from OMS. These reports will be updated to allow for the querying of SCADA historian and ADMS information.

Due to the secure IT network the existing Siena Reports will only be accessible from the secure IT network. To provide non-ADMS users with necessary outage data new "dashboards" and automated reports will be created that can be accessed via the Corporate IT network.

Many other OMS system integrations will be modified as needed to achieve the necessary ADMS IT secure network requirements.

Schedule

Unitil's ADMS deployment and system integration improvements began in early 2020. This initial Corporate ADMS deployment, including the functionalities described in section 3.1 above is expected to be completed by the end of 2023 with FG&E scheduled to be complete by the end of 2022 and UES being complete by the end of 2023.

Deployment of VVO and the transition to ABB SCADA (with the exception of the substations/circuits to confirm VVO functionality) are included in DOC specific VVO and SCADA projects.

4 Future Corporate ADMS Deployment

In addition to the ADMS functionalities and integrations described above in section 3 Unitil is proposing the following ADMS "enhancements" that are outside the scope of the current Corporate ADMS deployment project.

Distributed Energy Resource Management System (DERMS)

While not part of the initial implementation of ADMS it is Unitil intention to implement a DERMS in the future. The Company's vision is to utilize ADMS/DERMS to manage and control multiple DER facilities and other infrastructure (electric vehicle charging stations, load curtailment, etc.) including both company owned and customer owned facilities. DERMS will provide the information and control necessary to effectively manage the technical challenges posed by a more complex grid. The DERMS system provides the utility the ability manage the impact of DER and operate the system more efficiently.

DERMS is an integral module of the ABB ADMS that Unitil is in the process of implementing. After the initial Corporate ADMS deployment it is the Company's intention to purchase and activate the DERMS license and integrate systems and data as needed for deployment.

Unitil will require significantly more visibility and control of the DERs that will participate in the DERMS program including real-time invertor status, real and reactive power output, and voltage information. In the cases of energy storage Unitil will also need real-time information on available storage and dispatch control over the energy storage facility. It is the Company's vision that these will be integrated via the Company's SCADA/ADMS.

Initially Unitil plans to utilize DERMS to manage real and reactive power needs, but the system will have the capability to perform voltage management and be integrated into the VVO algorithm.

With the exception of the two Unitil owed DER facilities (one PV facility, one Battery Storage facility) Unitil does not have a proposed timeframe for controlling other DER facilities. It is the Company's intent to deploy DERMS on these two Unitil owned DER facilities and any additional Unitil DER facilities (unknown at this time) on-line at the time of DERMS deployment to confirm DERMS operates as expected. Once complete it is Unitil expectation that DERMS will be available to control non-Unitil owned DER.

Unitil currently plans to start deploying DERMS in 2024 after the initial Corporate ADMS deployment is complete. It is expected to take two years to implement DERMS and integrate with Unitil owned DER facilities.

4.1.1 Distribution State Estimation

Although Unitil does not have plans to implement distribution state estimation, the ABB DERMS module has the ability to perform distribution state estimation that includes look ahead load, generation and DER output forecasting. In the event there is a need to implement distribution state estimation in the future “day before” hourly historical consumption data from all (or nearly all) customers on the Unitil system will be required.

Model Exporting to Other Systems

Unitil plans to contract Siena to develop an export engine to allow for the export of ADMS models, including circuit topology and connectivity and customer load and generation data that can be easily imported in circuit analysis software. This will greatly improve the Company's ability to plan its distribution system at various load levels.

Unitil currently plans to begin this effort in 2023 during the final year of the initial Corporate ADMS deployment. It is expected that this effort will take approximately eighteen months to complete.

Heat Map and Host Capacity Mapping

Unitil believes that it could be possible to utilize ADMS to create heat maps and host capacity maps that display constrained areas of the system as well as areas that could support additional DER penetration. This will require significant additional review and scoping, but with ADMS containing the most update circuit modelling information it could be the ideal platform to utilize for “real-time” maps generated historical or future load levels. These maps could be published similar to the Company’s outage map(s) and be updated at predefined intervals (daily, weekly, etc.)

It is the Company’s intent to investigate the feasibility of utilizing ADMS to create these maps and if deemed feasible will scope and evaluate the project in detail for potential implementation in 2024 with a possible completion in 2025.

5 Future Considerations and Challenges

Some of the significant challenges that could impact the Company’s ADMS performance in the future are listed below. At this time Unitil does not know if or when modifications will be required to address these challenges or what the scope of the improvements will need to be.

Customer Metering Information

Unitil’s current AMI system does not have the capability to provide “real-time” customer metering information. Unitil currently plans to utilize a relationship it is developing between large scale PV with “real-time” SCADA telemetry and small scale PV without “real-time” metering information to establish an assumed “real-time” PV output. As energy storage is deployed at existing sites or new sites “real-time” metering information of the energy storage could be integral to maintaining accurate ADMS models.

Additionally, as DER penetration increases there could be a need to switch from the model based VVO algorithm to a measurement based VVO algorithm. The Company’s ADMS has the ability to do this, but will require “real-time”, “interval” customer voltage measurements, which the Company’s current AMI system is not capable of.

GIS Utility Network Model

It is anticipated that the Company’s GIS model will transition to the Utility Network Model within the next several years. Although it is unknown at this time what impact this will have, it is anticipated that ABB will need to make upgrades to the ADMS platform, Siena will need to make changes to the GIS/ADMS import engine and Unitil will need to make changes its GIS model.

6 Additional DOC Deployment

Additional VVO, SCADA and DERMS deployment beyond the locations being utilized to confirm he performance of ADMS functionality described in this document will be include in DOC specific projects and not the Corporate ADMS deployment project(s).

APPENDIX C

Benefit Cost Analysis

		20 Year NPV					15 Year NPV			
Row	Projects	NPV Benefits (000's)	NPV Capital Costs (000's)	NPV O&M Costs (000's)	B/C Ratio		NPV Benefits (000's)	NPV Capital Costs (000's)	NPV O&M Costs (000's)	B/C Ratio
1	Field Area Network	$0	$2,541	$586	-		$0	$2,541	$430	-
2	ADMS and DERMS	$0	$1,855	$543	-		$0	$1,855	$451	-
3	Volt/VAR Optimization	$21,841	$14,985	$0	1.46		$16,500	$14,985	$0	1.10
4	SCADA	$9,040	$4,816	$0	1.88		$6,806	$4,816	$0	1.41
5	Mobile Damage Assessment	$8,412	$385	$281	12.63		$7,221	$385	$237	11.61
6	AMI/OMS Integration	$1,445	$92	$64	9.26		$1,241	$92	$54	8.50
7	Data Sharing Platform	$0	$385	$329	-		$0	$385	$278	-
8										
9	Totals	$ 40,739	$ 25,059	$ 1,804	1.52		$31,768	$25,059	$1,450	1.20
10										
11	Summary	10 Year	15 Year	20 Year						
12	Total Benefits	$31,909	$67,367	$103,002						
13	Total Capital Costs	$34,323	$43,332	$43,332						
14	Total O&M Costs	$1,557	$2,913	$4,320						
15										
16	Discount Rate	8.0%								

	Project Benefits (000's)																				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	Total
Projects	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	Benefits
Field Area Network	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ADMS and DERMS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Volt/VAR Optimization	$ -	$ -	$ 186	$ 875	$ 1,320	$ 1,795	$ 2,207	$ 2,584	$ 3,051	$ 3,501	$ 4,243	$ 4,243	$ 4,243	$ 4,243	$ 4,243	$ 4,243	$ 4,243	$ 4,243	$ 4,243	$ 4,243	$ 57,954
SCADA	$ -	$ -	$ 182	$ 359	$ 536	$ 713	$ 890	$ 1,067	$ 1,244	$ 1,421	$ 1,598	$ 1,775	$ 1,775	$ 1,775	$ 1,775	$ 1,775	$ 1,775	$ 1,775	$ 1,775	$ 1,775	$ 23,987
Mobile Damage Assessment	$ -	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 946	$ 17,973
AMI/OMS Integration	$ -	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 163	$ 3,088
Data Sharing Platform	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Totals	$ -	$ 1,109	$ 1,477	$ 2,342	$ 2,965	$ 3,616	$ 4,205	$ 4,759	$ 5,404	$ 6,031	$ 6,950	$ 7,127	$ 7,127	$ 7,127	$ 7,127	$ 7,127	$ 7,127	$ 7,127	$ 7,127	$ 7,127	$ 103,002

	Project Capital Costs (000's)																				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	Total
Projects	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	Costs
Field Area Network	$ -	$ 90	$ 56	$ 127	$ 626	$ 325	$ 463	$ 780	$ 811	$ 640	$ 704	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,622
ADMS and DERMS	$ 350	$ 668	$ 468	$ 378	$ 298	$ 170	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,331
Volt/VAR Optimization	$ -	$ -	$ 383	$ 2,000	$ 2,929	$ 2,731	$ 2,862	$ 2,880	$ 3,416	$ 3,488	$ 4,292	$ 2,783	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 27,764
SCADA	$ -	$ -	$ 1,530	$ 1,740	$ 760	$ 790	$ 250	$ 340	$ 420	$ 550	$ 760	$ 470	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,610
Mobile Damage Assessment	$ -	$ 449	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 449
AMI/OMS Integration	$ -	$ 107	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 107
Data Sharing Platform	$ -	$ 449	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 449
Totals	$ 350	$ 1,763	$ 2,437	$ 4,245	$ 4,612	$ 4,016	$ 3,575	$ 4,000	$ 4,647	$ 4,678	$ 5,756	$ 3,253	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 43,332

	Project O&M Costs (000's)																				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	Total
Projects	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	Costs
Field Area Network	$ -	$ -	$ -	$ 4	$ 23	$ 32	$ 47	$ 71	$ 94	$ 106	$ 124	$ 124	$ 124	$ 124	$ 124	$ 124	$ 124	$ 124	$ 124	$ 124	$ 1,617
ADMS and DERMS	$ 44	$ 46	$ 47	$ 48	$ 50	$ 51	$ 53	$ 55	$ 56	$ 58	$ 60	$ 61	$ 63	$ 65	$ 67	$ 69	$ 71	$ 73	$ 75	$ 78	$ 1,191
Volt/VAR Optimization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SCADA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mobile Damage Assessment	$ -	$ -	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 630
AMI/OMS Integration	$ -	$ -	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 8	$ 144
Data Sharing Platform	$ -	$ -	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 738
Totals	$ 44	$ 46	$ 131	$ 136	$ 157	$ 168	$ 183	$ 209	$ 235	$ 248	$ 268	$ 269	$ 271	$ 273	$ 275	$ 277	$ 279	$ 281	$ 284	$ 286	$ 4,320

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY

OF

CINDY L. CARROLL

CARLETON B. SIMPSON

CAROL VALIANTI

EXHIBIT CSV-1

New Hampshire Public Utilities Commission

Docket No. DE 21-030

TABLE OF CONTENTS

Exhibits

I. INTRODUCTION AND SUMMARY

Q. Ms. Carroll, please state your name and business address.

A. Cindy Carroll, 325 West Road, Portsmouth, New Hampshire.

Q. For whom do you work and in what capacity?

A. I am the Vice President of Customer Energy Solutions at Unitil Service Corp. ("Unitil Service"), an affiliate of Unitil Energy Systems, Inc. ("UES" or the "Company"). Unitil Service provides, at cost, a variety of administrative, managerial and professional services on a centralized basis to Unitil Corporation's ("Unitil") affiliates, including UES. In this testimony, we refer to Unitil Service and Unitil's utility operating companies collectively as the "Unitil Companies." My primary responsibilities are the development, implementation, and advancement of Unitil's distribution utilities' business expansion and economic development programs, energy efficiency programs, and critical customer management.

Q. Please describe your professional and educational background.

A. I possess more than twenty years of experience in the utility industry working on matters directly related to business expansion, account management and customer field services. I joined Unitil Service in October 1997 and have held several positions of increasing responsibility. I hold a Master's Degree in Business Administration from Southern New Hampshire University and a Bachelor of Arts degree in Communications from the University of New Hampshire.

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("Commission")?

A. Yes, I have testified before the Commission on numerous occasions on behalf of UES and Northern Utilities, Inc.

Q. Mr. Simpson, please state your name and business address.

A. Carleton Brown Simpson, 6 Liberty Lane West, Hampton, New Hampshire.

Q. What is your position and what are your responsibilities?

A. I am Regulatory Counsel for Unitil Service. In this position, I represent the Company in regulatory and legal proceedings. My primary responsibilities include the development of clean energy strategy related to electrification, transportation, energy storage, data sharing, and decarbonization.

Q. Please describe your educational background and professional experience in the energy and utility industries.

A. I have held a variety of engineering, compliance, external affairs, regulatory, and legal positions while at Unitil Service. I started my career at Unitil Service in 2013 in the role of Compliance Engineer. I was promoted to NERC Regulatory Compliance Specialist in 2016, Director of Government Affairs in 2017, and Regulatory Counsel in 2019.

I received a Bachelor of Science degree in Electrical Engineering, Summa Cum Laude, from the University of New Hampshire ("UNH") in 2012 and a Master of Science degree in Electrical and Computer Engineering from Worcester Polytechnic Institute with a concentration in electric power systems in 2014. I also earned a Juris Doctor focused in

Energy and Environmental Law from Suffolk University Law School in 2019. I am a member in good standing of the New Hampshire Bar and U.S. District of New Hampshire Bar.

In 2012, I converted a gasoline-powered motorcycle to battery electric as a capstone engineering project while at UNH and was awarded "Best Presentation" at the 2012 Undergraduate Research Conference. From August 2018 through October 2020, I served on the New Hampshire General Court's SB 517 Electric Vehicle Charging Stations Infrastructure Commission on behalf of the Company.

Q. Have you previously testified before the New Hampshire Public Utilities Commission or other regulatory agencies?

A. I have not previously filed testimony before the New Hampshire Public Utilities Commission. I have provided written testimony before the Massachusetts Department of Public Utilities in Docket 16-148, petition for approval of a request to purchase, own and operate a 1.3 megawatt ("MW") solar facility by the Company's regulated Massachusetts affiliate, Fitchburg Gas and Electric Light Company.

Q. Ms. Valianti, please state your name and business address.

A. Carol Valianti, 6 Liberty Lane West, Hampton, New Hampshire.

Q. What is your position and what are your responsibilities?

A. I am the Vice President, Communications and Public Affairs for Unitil Service. My responsibilities include the development, execution and operations leadership for the Company's strategic communications including Customer Communications, Digital

Communications, Public Relations, Employee Communications and Engagement, Community Development, and Emergency Response Communications.

Q. Please describe your business and educational background.

A. I earned a Bachelor of Arts degree in American Studies and Communications from Fairfield University in 1989. Following graduation, I was employed by Major League Baseball, working in various broadcasting and communications managerial roles. Following Major League Baseball, I was employed by Malden Mills in marketing and communications roles including as Vice President, Global Communications and then by Segway as Vice President, Global Communications. I joined Unitil Service in September of 2009 as the Vice President, Communications and Public Affairs.

Q. Have you previously testified before the Commission or any other Regulatory agencies?

A. No, I have not previously filed testimony before the New Hampshire Public Utilities Commission.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to provide the Commission with an overview of the Company's request for approval of three programs: (1) a suite of time of use ("TOU") rate offerings, (2) an electric vehicle infrastructure development program ("EV Program"), and (3) a Marketing, Communications, and Education ("MC&E") Plan to increase customer awareness of electric vehicles ("EVs") and engage with customers about the TOU rates and EV Program offerings as described herein. These initiatives are intended to enable adoption of distributed energy resources ("DERs"), transportation electrification, and individualized energy management to reduce carbon emissions from the electricity sector while providing savings for our customers. The technology, environmental & climate policy, and market forces driving this evolution are discussed in Part II.

Part III of this testimony discusses the suite of proposed TOU rates. The Company recognizes that varying customer behaviors may necessitate a suite of EV charging rate structures, including fixed rates and TOU options. Proper rate design will balance demand and energy charges to ensure cost causation while enabling EV adoption. Pricing structures must be simple and easily understood to promote managed or smart charging to best utilize existing system capacity and mitigate environmental impacts. The TOU rate offerings proposed includes a "whole-house" residential TOU rate and separately-metered EV TOU rates for residential, small general service, and "high demand draw" large general service customers. These rates serve as a foundation for the EV Program, customer behavioral changes to mitigate peak demand, and other future customer investments in DERs.

In Part IV of our testimony, we describe the Company's proposed EV Program that is structured to stimulate the EV market in New Hampshire. The EV Program contains two initiatives: (1) a behind-the-meter partnership program to incentivize residential customers to procure and install smart Level 2 electric vehicle supply equipment ("EVSE") for charging at their homes, and (2) a public "make-ready" EV infrastructure program to expand the availability of charging stations in New Hampshire.

Finally, Part V of our testimony discusses the MC&E Plan that is designed to meaningfully increase consumer awareness, interest in, and adoption of EVs, EV charging infrastructure and EV TOU rates. The MC&E Plan consists of two parts: (1) a Consumer EV Education Campaign; and (2) a Consumer EV Marketing and Promotion Program. The Consumer EV Education Campaign will increase awareness of and inform the Company's customers about the benefits of EVs, options for home and public charging, and the proposed EV TOU rates. The Consumer EV Marketing and Promotion Program will focus on creating experiential learning opportunities for customers, partnerships with EV dealerships, and partnerships and incentives/rebates with behind-the-meter EVSE vendors.

II. TECHNOLOGY, ENVIRONMENTAL & CLIMATE POLICY, AND MARKET EVOLUTION

Q. Have advancements in energy technology affected the environment in which electric distribution companies such as UES operate?

A. Yes. Technology innovation has both accelerated and reinforced this transformation as customers now have access to services, markets, and home energy tools previously unimagined. Advancements in technology are driving down the cost of clean energy, making it more affordable for consumers. Energy markets continue to emerge as innovators develop new ways to control and manage energy usage and market new services directly to end-use customers.

As society adopts new technologies, and as DERs are increasingly connected to the distribution system, the fundamental architecture of the electricity delivery system (the "grid") must change. The 20th Century electric grid, originally designed to distribute power from large centralized generating plants, must now integrate a wide array of distributed load, storage and generation resources. A grid that was designed for "one-way" power flow must now accommodate two-way power flow, increasing the need for sophisticated protection, communication, metering, and intelligence. The grid must also provide opportunities for customers to understand and actively participate in energy markets to enhance efficient utilization and consumption of electricity, while delivering improved reliability and power quality.

Utility operations are transitioning away from the traditional model of energy delivery, to one that integrates and optimizes the needs and interests of consumers, producers, markets, service providers and other participants. New markets and new technologies are rapidly emerging in response to public policies, climate action, and the changing preferences of customers. We are seeing a significant transformation in how customers are powering their homes and businesses, including the ability to generate and store their own electricity. More recently, the promise of significant choice in EV options has moved the market from niche to mainstream. Implementing enabling technologies and programs to facilitate this transition will meet public demands while making the electric system more efficient, economic, and environmentally friendly.

For over a decade, the Company has visualized the utility of the future as an enabling platform with the capabilities to unlock the full potential of today's customers, markets and technologies. Our vision is to transform the way people meet their evolving energy needs to create a clean and sustainable future. Distributed energy resources, including EVs, are essential elements in this transition. The proposed program offerings described herein represent a step towards the Company's utility of the future.

Q. What are the environmental drivers behind these new program offerings?

A. The global imperative of combating climate change and reducing carbon emissions has driven a fundamental transformation of the energy sector. In its *2020 Corporate Sustainability & Responsibility Report*, Unitil outlined its goal to be the most technologically advanced utility in the region in order to realize the promise of a fully modernized grid and clean energy future. [1] The Company's vision of the modern grid as an "enabling platform" will empower customers to adopt new technologies through a transition of distribution operations to distributed energy resources, enhancing the customer experience, and supporting diverse actions by customers and third-party providers.

Electrification of the transportation sector represents an opportunity to dramatically reduce greenhouse gas ("GHG") emissions with electric utilities representing a critical enabling stakeholder. According to the U.S. Energy Information Administration ("EIA"), New Hampshire's largest source of carbon dioxide ("CO_2") emissions is the

[1] "2020 Corporate Sustainability & Responsibility Report." *Unitil Corporation*, https://unitil.com/2020-Sustainability-Report/.

transportation sector, representing approximately half of all CO_2 emitted.[2] Transportation is also the largest source of greenhouse gas emissions nationally according to the Environmental Protection Agency ("EPA"), with more than 90 percent of the fuels used coming from petroleum sources.[3] Addressing emissions and reducing energy intensity in the transportation sector is vital to meeting New Hampshire's environmental goals and objectives.[4] As EVs produce zero direct emissions and typically produce fewer life cycle emissions relative to conventional vehicles, transportation electrification represents a key opportunity to solve society's current climate and environmental challenges.[5]

Q. Please describe recent directives from the White House regarding advancing clean transportation.

A. On January 20, 2021, President Biden issued an Executive Order on Protecting Health and the Environment and Restoring Science to Tackle the Climate Crisis.[6] Sec. 2(iii) of the Order directs the National Highway Traffic Safety Administration ("NHTSA") and EPA to review and possibly reconsider rules related to fuel economy standards for passenger vehicles and trucks. On January 27, 2021, President Biden issued an Executive

[2] "State Carbon Dioxide Emissions Data." *U.S. Energy Information Administration*, March 2, 2021, https://www.eia.gov/environment/emissions/state/.
[3] "Sources of Greenhouse Gas Emissions." *U.S. Environmental Protection Agency*, https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions.
[4] "New Hampshire 10-Year State Energy Strategy." *New Hampshire Office of Strategic Initiatives*, April 2018, https://www.nh.gov/osi/energy/programs/documents/2018-10-year-state-energy-strategy.pdf.
[5] "Reducing Pollution with Electric Vehicles." *U.S. Department of Energy*, https://www.energy.gov/eere/electricvehicles/reducing-pollution-electric-vehicles.
[6] "Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis." *The White House*, January 20, 2021, https://www.whitehouse.gov/briefing-room/presidential-actions/2021/01/20/executive-order-protecting-public-health-and-environment-and-restoring-science-to-tackle-climate-crisis/.

Order on Tackling the Climate Crisis at Home and Abroad.[7] Part II Sec. 205(ii) outlines the Federal Clean Electricity and Vehicle Procurement Strategy to develop a plan to facilitate the procurement of "clean and zero-emission vehicles for Federal, State, local, and Tribal government fleets, including vehicles of the United States Postal Service."[8] Furthermore, on March 2, 2021, the White House hosted a meeting led by National Climate Advisor Gina McCarthy with CEOs from EV charging infrastructure companies to support the Biden Administration's goal to build more than 500,000 EV chargers.[9]

Q. Please describe the current state of EV adoption in New Hampshire and the Company's projections for the future.

A. The Company has analyzed actual EV registration data from the State of New Hampshire and developed EV adoption projections through 2031 based on compiled data from the Edison Electric Institute ("EEI") and Institute for Electric Innovation ("IEI"). From the State registration data, UES believes that approximately 5,070 EVs are registered in New Hampshire as of January 2021. Exhibit CSV-2. We estimate that 580 EVs are registered in municipalities where the Company provides electric service. Exhibit CSV-3. EEI and IEI developed a consensus forecast of EV sales projections from 2018 to 2030 based on five independent forecasts: Bloomberg New Energy Finance, Boston Consulting Group,

[7] "Executive Order on Tackling the Climate Crisis at Home and Abroad." The White House, January 27, 2021, https://www.whitehouse.gov/briefing-room/presidential-actions/2021/01/27/executive-order-on-tackling-the-climate-crisis-at-home-and-abroad/.
[8] Id.
[9] "Readout of the White House's Meeting with Electric Vehicle Charging Infrastructure Leaders." *The White House*, March 2, 2021, https://www.whitehouse.gov/briefing-room/statements-releases/2021/03/02/readout-of-the-white-houses-meeting-with-electric-vehicle-charging-infrastructure-leaders/.

Energy Innovation, U.S. Energy Information Administration, and Wood Mackenzie.[10] Applying this adoption model to the Company's New Hampshire service territories yields approximately 3,753 EVs registered by 2028 and 6,767 electric vehicles registered by 2031. Exhibit CSV-3. The Company's TOU rate offerings, EV Program, and MC&E Plan are intended to support these vehicles and customers in the transition to electric transportation.

Q. Please describe recent developments from original equipment manufacturers ("OEMs") in the vehicle market.

A. Automobile OEMs have made significant commitments to develop the EV market as of late. A recent industry survey conducted by CarGurus found that more than half of Americans believe that they will probably or definitely own an EV within the next ten years.[11] Jaguar, Volvo, and General Motors have committed to fully electrifying their model ranges by 2025, 2030, and 2035, respectively.[12] Honda, BMW, Ford, Hyundai, Kia, Mercedes-Benz, Nissan, Stellantis (formerly Fiat Chrysler Automobiles), Toyota, and Volkswagen have announced that they will be releasing electrified vehicle options within the next few years.[13]

Q. Please explain the power levels and connector types for EV charging.

[10] "Electric Vehicle Sales Forecast and the Charging Infrastructure Required Through 2030." *Edison Electric Institute*, November 2018, https://www.edisonfoundation.net/-/media/Files/IEI/publications/IEI_EEI-EV-Forecast-Report_Nov2018.ashx.
[11] "Are electric vehicles poised to kill the gasoline engine car? Welcome to the 'golden age' of EVs." *USA Today*, March 11, 2021, https://www.usatoday.com/story/money/cars/2021/03/11/electric-vehicles-tesla-gm-lucid-rivian-volvo-gas-cars/4581584001/.
[12] "Here Are Automakers' Plans for Adding More Electric Vehicles to Their Lineups." *Consumer Reports*, March 11, 2021, https://www.consumerreports.org/hybrids-evs/why-electric-cars-may-soon-flood-the-us-market/.
[13] Id.

A. EV charging segments include Level 1, Level 2, and Direct Current Fast Chargers ("DCFCs").[14] Level 1 charging occurs at 120 volts ("V") alternating current ("AC") using a standard electrical outlet and may require more than 24 hours to fully charge an EV, depending on charging rate and battery capacity. Level 2 chargers utilize a 240V AC connection and can fully charge most EVs in approximately 12 hours or less, depending on charging rate and battery capacity. DCFCs use direct current ("DC") with power outputs currently ranging from 50 kilowatts (kW) up to 350 kW, with higher outputs expected in the future, and can typically fully charge an EV in approximately an hour.

EV charging connectors can vary by vehicle type and manufacturer. Tesla vehicles utilize a proprietary connector for native charging at all levels, but also can be charged using the standardized connectors discussed below through the use of adaptor plugs.[15] SAE J1772 is the industry standard for all EVs charging at Level 1 or 2. For DCFC, CHAdeMO and SAE Combined Charging System (CCS) offer charging depending on the vehicle OEM. CHAdeMO currently supports charging up to 62.5 kW with a future versions supporting up to 900 kW for heavy-duty vehicles.[16] SAE CCS currently supports charging up to 350 kW.

III. TIME OF USE (TOU) RATE PROPOSALS

[14] "Electric vehicle (EV) charging standards and how they differ." *Elektrek*, March 5, 2021, https://electrek.co/2021/03/05/electric-vehicle-ev-charging-standards-and-how-they-differ/.
[15] "CCS1 to Tesla Adapter Finally Available for North American Market." *InsideEVs*, December 31, 2020, https://insideevs.com/news/463721/tesla-ccs-fast-charge-adapter-setec/.
[16] "New CHAdeMO 3.0 aims to harmonize global EV quick-charging standards." *SAE International*, May 28, 2020, https://www.sae.org/news/2020/05/chademo-3.0-to-harmonize-global-ev-quick-charging-standards.

Q. Please describe the Company's approach to offering TOU rates.

A. While current fixed electricity rate structures have proven sufficient to enable early adoption of new technologies, including EVs and DERs, the Company believes that a suite of TOU rates will encourage energy conservation, optimal and efficient use of grid facilities, and mitigate increases in peak demand. The Company offering includes a residential whole-house TOU rate, residential EV TOU rate, and EV TOU rates for small and large general service applications. Given the dynamic nature of the transportation market and the wide variety of customer travel needs, it is unlikely that any one option will be suitable for all customers. Innovative rate designs will afford customers the opportunity to adopt new technologies, manage energy consumption and enhance efficient utilization and consumption of electricity to save money.

In October of 2019, the National Association of Regulatory Utility Commissioners ("NARUC") released *Electric Vehicles: Key Trends, Issues, and Considerations for State Regulators*.[17] The two main principles of EV-specific rate design were identified as follows: (1) rate design should encourage efficient usage of existing assets rather than undergoing expensive distribution system upgrades to serve EVs, and (2) bill increases due to EV infrastructure upgrades should be kept to a minimum for customers who do not own EVs.[18] Perhaps most importantly, the NARUC report provides that EV adoption

[17] "Electric Vehicles: Key Trends, Issues, and Considerations for State Regulators." *National Association of Regulatory Utility Commissioners*, October 2019, https://pubs.naruc.org/pub/32857459-0005-B8C5-95C6-1920829CABFE.
[18] Id. at 25.

could lead to lower rates for all electric customers.[19] Fixed system costs, particularly when viewed in the context of TOU rates, may be spread across added volumes from electrification, potentially reducing electric rates for all customers.

The overarching objective of rate design is the pricing for grid services that adhere to the principles of fairness, transparency and economic efficiency. Transparent and economically efficient pricing structures will ensure a viable and sustainable long-term model that provides sufficient revenue to support the modernization of the electric system. Innovative rate design encourages appropriate behaviors and assures fairness and equity among customers.

The Company recognizes the evolving needs of the public that have occurred over the last several years and that are expected to continue in the future as customers transition from passive recipients to active participants in the energy market. The transition from offering traditional rate designs to tailored and more personalized options, especially for EV owners, is an important step to fulfill customers' evolving requirements from their utility. Customer education is an important aspect to innovative rate design. A strong customer communication, education and outreach plan is required to support new rate offerings. Customers will be more likely to adopt new rate structures if they are aware of and understand the new rates. Offering tools that help customers compare rate offerings is critical for beneficially influencing individual usage patterns and resulting bill impacts.

Q. Please describe the Company's proposed TOU rates.

[19] Id. at 21.

A. The Company proposes to offer a suite of TOU rates to enable customer adoption of new technologies, reduce peak demand, support energy efficiency and optimization, reduce emissions, and stimulate opportunities for retail market activity through the distribution system. The rates proposed include: (1) domestic "whole-house" TOU (TOU-D); (2) domestic EV TOU (TOU-EV-D); (3) small general service EV TOU (TOU-EV-G-2); and (4) large general service EV TOU (TOU-EV-G1). The development of these rates was informed by the Commission's findings in Order 26,394 that resulted from IR 20-004, *Investigation of Electric Vehicle Rate Design Standards, Electric Vehicle Time of Day Rates for Residential and Commercial Customers*, and the ongoing EV TOU proceeding DE 20-170, *Electric Vehicle Time of Use Rates*. Please see the Direct Testimony of Company witness John Taylor, Exhibit JDT-1, supporting the calculation of these rates.

i. Domestic "Whole-House" TOU (TOU-D)

The whole-house, domestic TOU rate is offered to allow residential customers to benefit from time-based energy optimization without the costs of a separate service. This rate is an important option for both EV and non-EV customers who want to change their behaviors and usage to reduce costs and peak demand. Customers will have the opportunity to realize savings for all uses, including EV charging.

Principles supported within the design of the whole-house TOU rate include:

- Seasonality is reflected in the rate;
- The rate incorporates load management techniques;
- The rate is based directly on cost causation principles;

- Energy supply and transmission billing components are time-varied;
- Three time periods are included (off peak, mid-peak and peak);
- The rate is seasonally differentiated ("summer" and "winter" rates that change coincident with default service adjustments);
- The peak period is five hours in duration; and
- The rate does not include a demand charge.

These principles are consistent with the guidelines set forth in Order 26,394. Please see Exhibit CSV-4 for an illustrative tariff for the TOU-D rate.

ii. Domestic EV TOU (TOU-EV-D)

EEI predicts that approximately 80% of EV charging happens and will continue to occur at the home; therefore, it is important for customers to have options for residential charging, including TOU rates.[20] The separately-metered residential EV TOU rate has been tailored to the unique charging needs and characteristics of EVs at customers' homes. As EVs are adopted in greater numbers, a dedicated residential rate class for EV charging only will represent a key customer option. The proposed rate offers incentivized off peak charging with significantly more expensive mid-peak and peak rates. An additional, dedicated meter ensures that EV charging has a discrete rate class, is controllable through demand response programs, and is individually measured and managed apart from other loads.

[20] "Electric Vehicle Sales Forecast and the Charging Infrastructure Required Through 2030." *Edison Electric Institute*, November 2018, https://www.edisonfoundation.net/iei/publications/Documents/IEI_EEI%20EV%20Forecast%20Report_Nov2018.pdf.

In accordance with the Commission's findings in Order 26,394 for residential EV TOU:

- Seasonality is reflected in the rate;
- The rate incorporates load management techniques;
- The rate is based directly on cost causation principles;
- All three billing components (supply, transmission, and distribution) are time-varied;
- Three time periods are included (off peak, mid-peak and peak);
- The rate is seasonally differentiated ("summer" and "winter" rates that change coincident with default service adjustments);
- The average annual price differential between off peak and peak is 3:1;
- The peak period is five hours in duration;
- The rate does not include a demand charge; and
- All customers on this rate will be separately-metered.

The Company believes that introducing a demand charge for residential customers is unnecessary at this time due to current levels of EV penetration. Residential customers are unlikely to be charging more than one EV using Level 2 charging. Therefore, significant demand increases by individual customers is not expected to result in the near term if charging occurs off peak. Furthermore, demand charges may present complexity resulting in customer confusion, requiring additional outreach and education to ensure desired charging behaviors. The Company also intends to leverage the residential EV TOU rate as a pathway to performing the alternative metering feasibility assessment as ordered by the Commission in Order 26,394. Further details are provided below in the

EV Program discussion within Part IV of our testimony. Please see Exhibit CSV-5 for an illustrative tariff for the TOU-EV-D rate.

iii. Small General Service EV TOU (TOU-EV-G2)

EV TOU rates for small general service customers are essential offerings to stimulate the EV market. Businesses, municipalities, and other small general service customers will continue to adopt and support EVs at an accelerating rate as EV availability continues to increase and become more affordable. Such customers may choose to utilize these rates to charge fleet vehicles, offer EV charging to patrons and customers, develop publicly available merchant EV charging, or other use cases. Off peak charging is necessary to mitigate peak demand and reduce charging costs for these customers as well. An additional, dedicated meter ensures that the small general service EV TOU G2 rate exists within a dedicated rate class, is manageable through demand response programs, and is discrete from other loads.

The separately-metered small general service EV TOU (TOU-EV-G2) rate is tailored to serve up to 200 kVA of load, or approximately up to ten Level 2 chargers charging at 19.2 kW peak. This customer demand designation aligns with the Company's current fixed (i.e. non time-varying) small general service (G2) customer class. In accordance with the Commission's findings in Order 26,394 for small commercial customer applications:

- Seasonality is reflected in the rate;
- The rate incorporates load management techniques;

- The rate is based directly on cost causation principles;
- Default energy supply and transmission billing components are time-varied;
- Three time periods are included (off peak, mid-peak and peak);
- The rate is seasonally differentiated ("summer" and "winter" rates that change coincident with default service adjustments);
- The peak period is five hours in duration;
- All customers on this rate will be separately-metered; and
- A temporary demand charge holiday is offered for these customers at 75% for year 1, 50% for year 2, 25% for year 3, and ending thereafter.

Unlike the residential EV TOU rate, the small general service EV TOU rate does include a demand charge component. The Company's current small general service (G2) customers have demand charges; therefore, an understanding of this billing component already exists amongst the applicable customer group. While a demand charge is present, the Company is proposing to offer customers that select the small general service EV TOU rate a temporary demand charge holiday. For years 1, 2, and 3, customers will be billed demand charges reduced by 75%, 50%, and 25%, respectively. After year 3, the full demand charge component will be billed. This program is intended to support the nascent state of the EV charging market, recognizing that during early years of operation, the demand charge component may present challenges for economic operation of EV charging sites. The demand charge holiday is further intended to support and incentivize broader customer adoption of EVs through the incentivized charging rate. Please see Exhibit CSV-6 for an illustrative tariff for the TOU-EV-G2 rate.

iv. Large General Service EV TOU (TOU-EV-G1)

The "high demand draw" large general service EV TOU rate provides passenger car fleet customers, heavy duty vehicles, or large public charging sites, including clustered Level 2 or DCFC, an optimized rate design. Off peak charging is necessary to mitigate peak demand and reduce charging costs for these customers as well. An additional, dedicated meter ensures that the large general service EV TOU G1 rate exists within a dedicated rate class, is manageable through demand response programs, and is discrete from other loads. The "high demand draw" rate is tailored to serve customers with more than 200 kVA of load, enabling sites with clustered Level 2 and DCFC chargers which currently range from 50 kW to 350 kW per charger.

In accordance with the Commission's findings in Order 26,394:

- Seasonality is reflected in the rate;
- The rate incorporates load management techniques;
- The rate is based directly on cost causation principles;
- The transmission billing component is time-varied;
- Three time periods are included (off peak, mid-peak and peak);
- The rate is seasonally differentiated ("summer" and "winter" rates that change coincident with default service adjustments);
- The peak period is five hours in duration;
- All customers on this rate will be separately-metered; and
- A temporary demand charge holiday is offered for these customers at 75% for year 1, 50% for year 2, 25% for year 3, and ending thereafter.

Similar to the small general service EV TOU G2 rate, the large general service EV TOU G1 rate includes a demand charge component. The Company's current large general service (G1) customers have demand charges, therefore an understanding of this billing component already exists amongst the applicable customer group. While a demand charge is present, the Company is proposing to offer customers that select the large general service EV TOU G1 rate a temporary demand charge holiday. For years 1, 2, and 3, customers will be billed demand charges reduced by 75%, 50%, and 25%, respectively. After year 3, the full demand charge component will be billed. This program is intended to support the nascent state of the EV charging market, recognizing that during early years of operation, the demand charge component may present challenges for economic operation of EV charging sites. The demand charge holiday is further intended to support and incentivize broader customer adoption of EVs through the incentivized charging rate. Please see Exhibit CSV-7 for an illustrative tariff for the TOU-EV-G1 rate.

v. TOU Ratemaking, Technological, and Customer Considerations

Q. What rate design principles have influenced the TOU rates proposed?

A. Innovative rate design is driven by timely and accurate data. Data has been leveraged from the Company's Advanced Metering Infrastructure ("AMI"), Meter Data Management System ("MDMS") and Customer Information System ("CIS") for the proposed, innovative rate designs. The Company believes that rates should be based on cost of service rate design principles to ensure economic efficiency and limit cost shifting. Marginal energy costs are typically driven by wholesale electric market (ISO New England in this case) factors and may not fluctuate for different customer segments.

EV adoption forecasts have been developed and indicate that such incremental loads may require new transformers, service lines and meter upgrades over time. Instances may also arise where the addition of loads would require an upstream feeder and/or substation upgrade.

The Company's TOU rate designs also take into account the effect technology adoption will have on the electric distribution system and subsequent system planning and investment. Technology adoption rates will be forecast over the coming years and those loads will be integrated into planning studies and load forecasts. Possible changes to engineering and construction standards may be warranted to ensure reliability, safety, and appropriate equipment sizing to account for an increase in electric load. The design of electric services may need to change as well, such as shorter distances and increased conductor size to address voltage drop concerns. Ongoing capital budgeting may need to accommodate early replacement of current infrastructure that is undersized and unable to accommodate new customer loads. Additionally, the Company has concluded that the installation of interval metering for all future TOU customers is prudent given the increasingly dynamic loads and generation that have the potential to export energy onto the distribution system and necessitate more granular planning analyses.

The Company believes that the rate design options for any type of electric load should reflect cost causation principles and be designed to promote the efficient use of the electric system resources and enable customers to reduce costs. Rate options must provide proper price signals and influence customer behavior in a manner that creates beneficial outcomes for the customer (through higher system utilization) and for the utility (through a reduction in system costs over time). To achieve these objectives, the design of the rate options should reflect system costs that are time-varying in nature, and provide customers a cost-based price signal through the rate design. The time-varying costs embedded within the rates offered here are intended to optimize system capacity and flatten the load curve.

Throughout the TOU rate design process, UES has worked to understand and evaluate how customers will respond to TOU rate options, anticipating future refinements to the TOU rate design given that load shape and resulting costs will likely change over time. The TOU rate designs aim to balance the desire of creating a significant peak-to-off-peak rate differential to increase the likelihood of a positive customer response while accurately reflecting, to the greatest extent possible, the underlying costs of the utility.

Incorporating considerations into the design of TOU rates that may be non-cost causative in the near-term will provide an opportunity to gauge the resulting longer-term impact of electrification on the electric distribution system. Affording rate benefits to customers who can change their electric usage patterns even though the utility does not experience a corresponding reduction in cost will help achieve non-cost causative objectives, such as supporting technology adoption, gaining an understanding of consumer behavior, and gaining insights into grid operations and future investment requirements by the utility.

Q. Why does the Company propose to time-vary all three billing components (energy, distribution, and transmission) within the proposed domestic EV TOU rate?

A. As a general proposition, rate design should strive to accurately reflect cost causation and avoid cost shifting. The overarching goal is to promote the transition of more customers to beneficial technologies, such as EVs. Rates with more sizable cost differentials between the peak and off peak rates will help to achieve this paradigm while mitigating peak load impacts. The Company believes including all three billing components (energy, transmission, and distribution) provides enough cost inclusion to incorporate a beneficial TOU rate differential while still reflecting a reasonable allocation of actual costs. Additionally, the Commission has expressed a preference for three-part TOU rate designs in Order 26,394 and approved a separately-metered EV TOU rate offered by Liberty Utilities in DE 19-064 (based upon the TOU rate approved for Liberty Utilities' Battery Storage Pilot Program in 17-189), which provides time-varying rates for supply, transmission, and distribution.

Q. Can customers on competitive supply select the EV TOU rates?

A. Yes. At this time, however, customers on competitive electric supply may only see or participate in time-varying distribution and transmission charges, as applicable. If competitive electric suppliers offer future products with time-varying supply service on the same intervals as the proposed TOU rates, the Company will work with those suppliers and customers to determine cost, process, and system alterations required to provide a similar service.

Q. Please describe the Company's approach to demand charges within the proposed EV TOU rates.

A. Demand charges are designed to capture the infrastructure costs to meet a customer's peak capacity requirement. Currently, only UES's small general and large general service customer classes have a demand charge component. EV charging stations, particularly DCFC, are susceptible to high demand charges as these sites draw significant amounts of energy (50 kW up to 350 kW per charging station). Some DCFC sites have low load factors and utilization, so a demand rate may create a barrier to entry for some competitive market charging infrastructure companies. UES believes that EV rates should be designed for off peak usage and to encourage managed charging capabilities (controllable power output depending on time and rate). However, for customers that cannot manage demand during peak system periods, the demand charge must reflect the service being provided. In order to stimulate the EV market in NH and meet the Commission's directive in Order 26,394 regarding demand charge alternatives, the Company has proposed demand charge holidays for the small and large general service EV TOU rates as discussed in Parts III(iii) and (iv) above.

Q. Please describe the Company's consideration of load management and demand response in designing the TOU rates.

A. Load management techniques represent an important consideration for EV rate design. First and foremost, the TOU rates as proposed encourage customers to charge EVs during times of reduced system demand via price signals. As EV adoption continues to grow, charging (particularly DCFC) has the potential to quickly magnify electricity demand peaks. However, as EV load is flexible, one goal of EV rate design should be to promote charging at times of low demand. Through rate design structures that maximize capacity availability and minimize system upgrades and costs, the benefits of added energy volumes from EV load can flow to all customers. Such techniques are often referred to as “managed charging” or “smart charging”. Additional opportunities for customers to manage load may arise through demand response offerings as part of the NHSaves energy efficiency programs which the Company believes will be complementary to TOU rates.

Q. Would non-EV customers be precluded from enrolling in the EV TOU rates?

A. Yes. These rates have been designed and optimized for EV charging with policy principles embedded to promote the adoption of EVs. The Company’s strategy has been to develop a suite of rates designed with specific uses in mind, such as EV customers in this case.

Q. Please describe how the Company plans to meter customers who elect to switch to TOU rates.

A. The Company will separately meter all EV TOU installations in accordance with the Commission’s findings in Order 26,394. Depending on the customer’s service configuration and requirements, the Company will install an interval-based AMI meter to provide TOU billing data and interval data for customer edification.

UES initially installed AMI in 2006; today, all electric customers currently have AMI meters. This early vintage AMI uses powerline carrier technology to receive daily reads for each meter. Landis & Gyr provides UES’s AMI within their Gridstream TS2 system which is capable of interval data recording using 4 separate meter registers and 2-way communication. UES is in the process of upgrading the existing "TS2" system and deploying new Gridstream "PLX" data collectors and associated systems. The Landis & Gyr PLX system is designed to be a replacement for the TS2 technology and, as such, is backwards compatible, meaning the PLX collectors and transmitters can communicate with existing TS2 AMI meters. The system can record 15 minute metered intervals and is capable of reading PLX meters three times per day. Meters deployed to new TOU customers and under the normal meter replacement cycle will utilize PLX-compatible meters which will allow interval data for customer and Company use. The Company's MDMS and CIS already support these enhanced AMI capabilities.

Q. Has the Company provided illustrative tariffs for each of the TOU rates proposed?

A. Yes. Please see the exhibits below for each of the respective illustrative TOU tariffs. The Company has characterized these tariffs as illustrative as the rates must be calculated based on the external delivery charge ("EDC") and default service rates in effect at the time permanent rates are approved.

- Domestic Delivery Service Schedule TOU-D: Exhibit CSV-4
- Schedule TOU-EV-D: Exhibit CSV-5
- Schedule TOU-EV-G2: Exhibit CSV-6
- Schedule TOU-EV-G1: Exhibit CSV-7

Q. Has the Company outlined service requirements and the installation process for future EV TOU customers?

A. Yes. Please see Exhibit CSV-8 for a description of the service requirements for EV TOU customers.

IV. EV PROGRAM INFRASTRUCTURE PROPOSAL

Q. Please describe the Company's EV Program proposal.

A. The Company is proposing an EV Program to stimulate the adoption of EV infrastructure and the EV charging market. The EV Program is focused on increasing the availability of charging stations, lowering the investment barrier faced by customers regarding infrastructure needed for ownership of charging stations, and preparing for integration of EVs with the electric distribution system. Robust charging infrastructure is required to allow travel, alleviate range anxiety, and fundamentally change customer behavior to facilitate an economic and environmentally sound transition to EVs.

The Company is proposing to facilitate the development of EV charging stations and infrastructure in New Hampshire through two initiatives encompassing the EV Program: (1) a residential behind-the-meter EVSE installation and incentive program, and (2) a "make-ready" public EV infrastructure installation program to expand public EV charging stations in New Hampshire.

i. Residential Behind-the-Meter EVSE Installation and Incentive Program

Q. Please describe the proposed residential behind-the-meter EVSE installation and incentive program.

A. The Company proposes to offer rebates of up to $600 for the procurement and installation of smart, managed Level 2 EV chargers to 500 residential EV TOU customers. This proposed program represents a culmination of efforts from IR 20-004 and the Commission's Order 26,394, as well as ongoing efforts in DE 20-170. The Company will further utilize the residential EV program as a means of assessing alternative metering capability from behind the meter EVSE as required in Order 26,394.

Residential customers represent an important class given the disproportionate ratio of charging at home versus other locations and the need to optimize EV loads to mitigate peak demand and new infrastructure costs. Level 2, residential home EV charging is estimated to represent approximately 80% of the EV charging market.[21] Industry analysts believe that electric system upgrades will be needed to handle the increased load from EVs and impacts will depend on charging locations on the distribution system along with the time of day when vehicles are charged.[22] Managing these impacts through smart charging can improve asset utilization and may mitigate needed system investments.

Managed charging can be accomplished in two ways: active management and passive management. Active managed charging is the practice of sending control signals to a vehicle or the charging equipment to adjust the time of charge, the rate of charge or otherwise direct charging behavior. Passive managed charging is the effort to influence charging times by modifying customer behavior through TOU rates. The Company is proposing to facilitate behind-the-meter partnerships via the incentive to encourage customers to install charging equipment that can be actively managed while providing an opportunity for the Company to assess EVSE alternative metering capabilities.

[21] "Charging at Home." *U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy*, https://www.energy.gov/eere/electricvehicles/charging-home.
[22] "Transportation & Mobility Research: Electric Vehicle Grid Integration." *National Renewable Energy Laboratory*, https://www.nrel.gov/transportation/project-ev-grid-integration.html.

Several market participants have advocated for the utilization of EVSE for metering purposes.[23] Commission Staff and the Commission have expressed a desire to further investigate this capability as a means of expanding EVSE deployment in the state while reducing barriers to customer installation of such technologies. In Order 26,394 at 13, the Commission stated that "further investigation of issues related to advanced metering functionality associated with EVSE embedded meters is warranted."

Q. How will the Company select eligible equipment that qualifies for the incentive?

A. UES will issue a public request for information ("RFI") to EVSE vendors and software providers to gather information on EVSE metering capability and participation in an evaluation pilot. The Company will seek responses from such EVSE providers, including software-based telematics equipment embedded within EVs, to gain an understanding of EVSE charging session data accuracy, availability, format, interface capabilities, data sharing, load metering, sub-metering, metering data disaggregation, remote control, volt/VAR capability, customer controls, testing, privacy, and cyber & physical security considerations. The Company will learn about embedded EVSE metering capability from the responses, determine what standards are used to ensure device accuracy and interoperability, and how stakeholders can obtain data from EVSE third parties.

From the RFI, UES will develop a residential EV charger "standard" based upon desired characteristics shared by available solutions providers. The Company will then issue a

[23] *See* Comments of Chargepoint, Inc in Docket No. IR 20-004: February 20, 2020 and July 31, 2020 and Docket DE 20-170: December 9, 2020 and January 8, 2021; Written Comments of Tesla, Inc. in Docket No. IR 20-004, July 25, 2020; Comments of Clean Energy NH, Conservation Law Foundation, NHDES, City of Lebanon and OCA in Docket DE 20-170: December 9, 2020

request for proposal ("RFP") to EVSE vendors for inclusion on the Company's list of chargers and solutions eligible for customers to receive a purchase incentive up to $600. In order for a charging solution to receive an incentive, the charger/software vendor must agree to share all charging session and embedded metering data with UES for five years. All participating residential EV customers will be required to enroll in the separately-metered domestic EV TOU rate where a Company AMI meter will be provided, enabling 15 minute interval data and enhanced data sharing capability. The Company will collect the data from participating EVSE vendors and the Company's EV TOU meters. UES will analyze and compare historical embedded EVSE data against the utility metering interval data to assess accuracy, availability, format, interface capabilities, data sharing, load metering, sub-metering, metering data disaggregation, remote control, volt/VAR capability, customer controls, testing, privacy, and cyber and physical security, along with other considerations that arise during the assessment.

The Company hopes to develop behind-the-meter partnerships with EVSE equipment providers and local installers as part of the EV Program to assist customers with the installation process. UES believes that the residential behind-the-meter EVSE installation and incentive program will provide benefits to customers, the electric grid, the local economy, and society-at-large. By incentivizing customers to install smart, managed EV charging equipment during the early stages of EV market growth, EV customers will benefit from future demand management, energy efficiency and optimization offerings. Managed charging functionality allows EV loads to be flexible, curtailing or adding charging load as electric system conditions warrant. While managed charging programs do not currently exist within the NHSaves energy efficiency programs, this is an area of interest and likely development. Encouraging customers to adopt this functionality at the beginning of EV ownership will enable future participation in demand management programs.

The Company will submit an annual report to the Commission outlining the number of residential customer participants in the program, incentives distributed, third party partners within the program, and periodic findings related to embedded metering and future use cases. At a time to be determined, but to likely coincide with efforts on going in DE 20-170, the Company will offer a recommendation for next steps in leveraging EVSE data for future service offerings specific to EV customers.

Q: Has the Company performed any cost benefit analysis on the proposed residential behind-the-meter EVSE installation and incentive program.

A: Yes. For illustrative purposes, the Company has screened the residential behind-the-meter EVSE installation and incentive program using the Granite State Test recently approved by the Commission to evaluate cost-effectiveness of the energy efficiency programs administered by UES under the Energy Efficiency Resource Standard ("EERS").[24] Exhibit CSV-9. This analysis was conducted to determine, generally, if the behind-the-meter EVSE installation and incentive program would be cost effective if operation of charging equipment is limited during the ISO-NE summer and winter peak periods. This would demonstrate tangible benefits from the program above and beyond

[24] On December 30, 2019, the Commission issued Order 26,322, approving the Benefit-Cost Working Group's recommendations to take effect for the 2021-2023 EERS term.

the benefits of advancing public policy and further assessing alternative metering capability from behind-the-meter EVSE.

Q: Explain the details of how the Company performed the cost benefit analysis on the proposed residential behind-the-meter EVSE installation and incentive program.

A: The Company used the same energy efficiency benefit cost model used to evaluate the 2021-2023 statewide energy efficiency plan. The modeling assumptions were as follows:

- 500 ENERGY STAR certified EV chargers enrolled with demand response capability through open communication protocols. Chargers are required to be networked so that they can be monitored and controlled remotely.
- Incentive is $600 per unit (equals total utility cost)
- The measure has a 10 year life, during which time the equipment is controlled during peak periods.
- Energy Savings = 50 kWh per unit annually as compared to a non-ENERGY STAR charger
- Demand Savings = 0.5 kW average per unit per year
- Energy load shape = all summer / winter peak
- Peak coincidence factor is 100% summer / winter

Q: What were the results of the analysis?

A: The result of the modeling is a benefit / cost ratio of 2.2. The net present value of the benefits when modeled are $654,000 with a total cost of $300,000 ($600 per unit with 500 total units). The Company is providing this analysis to illustrate that the behind-the-meter EVSE installation and incentive program could be cost effective however, since many of the assumptions used in this modeling could be adjusted for sensitivity analysis, the Company is providing this modeling in Exhibit CSV-9 for illustrative purposes only.

ii. "Make-Ready" Public EV Infrastructure Program

Q. Please describe the proposed "make-ready" public EV infrastructure program.

A. As part of the EV program, UES proposes to offer a make-ready EV infrastructure program essential to the development of public EV charging stations throughout New Hampshire. The make-ready program targets investment of approximately $4.0 million over five years to deploy EV charging at approximately 37 Level 2 and 8 DCFC public sites (total of 45 sites) in the Company's service area. UES further proposes to install required upgrades on the distribution system and to contract with third-party electrical contractors to install behind-the-meter "customer-side" infrastructure. Specifically, the make-ready investments the Company proposes to install and own includes the following electrical equipment, infrastructure, and connections:

- The distribution primary lateral service feed;
- The necessary transformer and transformer pad;
- The new service meter;
- The new service panel; and
- The associated conduit and conductor necessary to connect each piece of equipment.

At a minimum the "make-ready" program will provide adequate capacity for future growth. The Company recommends "future-proofing" installations by class as follows:

- 0 kVA to 200 kVA Make-Ready (Level 2 Charging):
  - Install make-ready infrastructure for 200 kVA load (up to ten Level 2 chargers)
  - Customer to supply a minimum of two Level 2 chargers initially

- 200 kVA to 1000 kVA Make-Ready (DCFC/Clustered Level 2):
  - Install make-ready infrastructure for up to 1000 kVA load
  - Customer to supply a minimum of two DCFC chargers initially with a peak cumulative output exceeding 200 kW

The Company has provided additional information regarding make-ready service requirements in Exhibit CSV-10.

The exact number of charging ports deployed will be determined in collaboration with participating customer site hosts, considering the unique real property, service requirements, and site layout. UES will help customers understand their options within the make-ready program with the goal of optimizing the number of charging ports to maximize the number of vehicles that can charge at each location. Participating customers will be required to provide EVSE with non-propriety charging plugs and networked functionality.

The Company will target make-ready site hosts with publicly-available, long-dwell time parking including but not limited to the following types of customers:

- Workplaces
- Fleet parking facilities
- Public parking lots, garages, parks, beaches, and transit hubs
- Hotels, hospitals, and educational institutions
- Federal, state, and municipal properties
- Dining, entertainment, and shopping plazas
- Multi-family and apartment buildings
- Low to moderate income communities

The proposed make-ready program represents a significant increase in Company-supported, customer-sided and behind-the-meter infrastructure. UES believes that the make-ready program is necessary to expand New Hampshire's network of charging stations, that the make-ready program is in the public interest, and will reduce barriers to investments in EV charging infrastructure.

According to the U.S. Department of Energy, New Hampshire has approximately 281 public charging outlets in the state.[25] This is significantly less than all surrounding states including Maine (503), Vermont (786), Massachusetts (3,469), Connecticut (1,154), and Rhode Island (474).[26] Experts in the EV field believe that New Hampshire is lagging behind other states in the region both in terms of EV adoption and the deployment of EV charging infrastructure.[27] The Company's proposed make-ready program will therefore meet a need regarding the adoption of electric vehicles and associated public charging infrastructure in New Hampshire.

Q. Is the Company proposing to make any investments in owning and operating EV charging stations within the make-ready program?

A. At this time, UES is not proposing to own or operate EV chargers within the make-ready program. The focus of the make-ready program is to support the installation and deployment of the electrical infrastructure required to promote and serve publicly

[25] "Electric Vehicle Charging Outlets by State." *U.S. Department of Energy, Alternative Fuels Data Center*, https://afdc.energy.gov/data/10366.
[26] Id.
[27] "If electric vehicles are the future, is New Hampshire ready? Are you?" *Megan Fernandes, Fosters Daily Democrat*, March 24, 2021, https://www.seacoastonline.com/story/news/local/2021/03/24/electric-vehicles-new-hampshire-charging-stations-range-anxiety/4665825001/.

available EVSE, including the infrastructure behind-the-meter, by offering a turn-key installation solution. UES intends to work with owners and operators of publicly available parking sites to deploy make-ready infrastructure with the eligible customer providing the EVSE charging stations utilizing non-proprietary, open standard connectors at their cost.

The Company will evaluate the success of the make-ready offering throughout the course of the program. If the make-ready infrastructure deployment goals are not met or additional EV charging needs are identified in New Hampshire, the Company will consider deploying Company-owned and operated EVSE in a future proposal to the Commission.

Q. How many sites are you proposing to develop with make-ready infrastructure?

A. The modeling of the five year program includes an investment in 37 Level 2 Public sites and 8 DCFC Public sites (total of 45 sites) in the UES service area. The US Department of Energy's ("DOE") Electric Vehicle Infrastructure Projection Tool ("EVI-Pro") Lite was used as a guide when choosing the number of sites to model. By entering the number of EVs to support with EVSE, the tool calculates the number of Public Level 2 and Public DCFC plugs needed. The Company's modeling as provided in Exhibit CSV-3 indicates that approximately 3,753 EVs will be registered in the UES electric service territory through 2028. This figure was entered into the EVI-Pro calculator along with the percent of drivers with access to home charging. According to U.S. Census Bureau data, approximately 71% of New Hampshire's homes are owner-occupied, meaning that such customers have control over their ability to charge at home.[28] The Company intends to provide full support for both battery electric vehicles ("BEVs") and plug-in hybrid electric vehicles ("PHEVs") and used the DOE's recommended vehicle mix for distribution of such models. The resulting EVI-Pro calculation indicates that in order to support 3,753 EVs, 338 public Level 2 charging plugs/ports and 51 public DCFC charging plugs/ports will be required. These results are provided in Exhibit CSV-11. This calculation led to the Company's recommendation to develop make-ready infrastructure at approximately 37 Level 2 sites and 8 DCFC sites with approximately 10 Level 2 plugs/ports and 6 DCFC plugs/ports at each respective site.

Q. Did the Company develop estimated make-ready costs for the Level 2 and DCFC scenarios?

A. Yes. UES developed estimated cost scenarios for both the Level 2 and DCFC proposals: (1) five 19.2 kW Level 2 chargers with ten total plugs/ports for a total of 96 kW of connected load, and (2) six 50 kW DCFC for a total of 300 kW of connected load. The Company estimates installed make-ready costs to be approximately $77,000 for the (1) Level 2 scenario and $143,000 for the (2) DCFC scenario. A breakdown of these estimates is provided in Exhibit CSV-12.

Q. Has the Company evaluated the economics of the proposed investment?

A. Yes, the Company has evaluated the proposed make-ready program using a discounted cash flow ("DCF") analysis. To perform this analysis, the Company used its existing and

[28] "QuickFacts: New Hampshire." *U.S. Census Bureau*, July 1, 2019, https://www.census.gov/quickfacts/fact/table/NH/PST045219.

long-standing customer contribution model. Under this approach, a DCF analysis is performed that compares the estimated distribution revenues (i.e., excluding revenues attributed to supply) to the estimated cost of service. The cost of service reflects the incremental costs associated with the program, including investment in facilities, depreciation expense, and property and income taxes. The distribution revenues reflect estimated customer usage applied to the respective distribution rates for each customer class. The annual cost of service and revenue cash flows are discounted to the present value at the Company's after tax real weighted average cost of capital. If the Net Present Value ("NPV") of the cash flows is at or above zero, then the proposed investment is considered economically feasible and should be accepted.

Using the Company's DCF analysis, we have modeled the proposed five year program in Exhibit CSV-13. The Company utilized the estimated costs discussed above and in Exhibit CSV-12 of $77,000 per Level 2 site (five 19.2 kW Level 2 chargers with ten total plugs/ports for a total of 96 kW of connected load**)** and $143,000 per DCFC site (six 50 kW DCFC for a total of 300 kW of connected load), respectively. The modeling of the program includes an investment of approximately $3.99 million over five years. The modeling uses UES' existing distribution rates to calculate revenue estimates in order to assess the economic feasibility of the projects at existing rate and forecasted demand. The analysis returns a NPV of $243,869 over a dynamic 10 year term (14 Years total). Modeling the program demonstrates that the additional revenues generated under existing distribution rates and expected usage and demand are sufficient to cover the Company's after-tax weighted-average cost of capital and provide recovery of project costs over a period of 10 years. From a financial perspective, these projects should be accepted and the incremental costs will not be borne by existing customers.

Q. How does the Company categorize and propose to recover the costs associated the make-ready EV infrastructure program?

A. As described in the direct testimony of Kevin E. Sprague, costs associated with the make-ready EV infrastructure program are categorized within the Company's Grid Modernization Plan. As Mr. Sprague explains in more detail, such costs undergo rigorous planning and budgeting processes to ensure the most cost-effective solution is proposed. The recovery of make-ready EV infrastructure and other Grid Modernization costs are proposed to be included in annual step adjustments described in the testimony of Messrs. Goulding and Nawazelski.

Q. Please describe the process for make-ready project approvals with customers.

A. The process for project approval will be as follows:

- Receive application from customer;
- Preapproval assessment with customer site visit;
- Determine where power source will come from (site must be within 300 ft of power source, not over a public way, and outside environmentally sensitive areas);
- Receive signed site host agreement and license agreement;
- Generate work order with engineering study;
- Obtain proof of purchase of EVSE (i.e. charging station) from customer;
- Arrange installation with 3rd party contractor

Please also reference Exhibit CSV-10 for additional make-ready installation detail.

Q. Will make-ready program installations be required to enroll in the Company's EV TOU rate offerings?

A. Yes. Any customer who develops EV charging stations through the Company's make-ready program will be required to enroll in the applicable TOU rate. Customers that develop make-ready sites from 0-200 kVA will be required to enroll in the small general service EV TOU rate (Schedule TOU-EV-G2). Customers that develop make-ready sites above 200 kVA will be required to enroll in the large general service "high demand draw" EV TOU rate (Schedule TOU-EV-G1).

Q. Have similar EV programs been approved in other jurisdictions?

A. Yes, make-ready programs have been approved by regulatory commissions as such investments are viewed as being in the public interest, will reduce barriers to investments in EV charging infrastructure, will meet a need regarding the adoption of electric vehicles that is unlikely to be met by the competitive EV charging market, and will not impede the competitive EV charging market.[29] State utilities commissions have approved make-ready programs in Massachusetts (Eversource, D.P.U. 17-05), Rhode Island (National Grid, Docket No. 4780), New York, (Consolidated Edison, Case No. 19-E-0065 and National Grid, Case No. 17-E-0238), California (Pacific Gas & Electric, Case A1701022,

[29] MA D.P.U. 13-182-A, Investigation by the Department of Public Utilities upon its own Motion into Electric Vehicles and Electric Vehicle Charging at 13.
https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9233599

San Diego Gas & Electric, Case A1801012, and Southern California Edison, Case A1701021) and Minnesota (Xcel Energy, Docket 18-643), among others.

Q. Please describe how your proposals align with New Hampshire's public policy initiatives.

A. Make-ready programs align with New Hampshire policy objectives and have been supported by several EV market participants and stakeholder groups.[30] In July 2019, the New Hampshire Department of Business and Economic Affairs ("NH BEA") released a report (*Evaluating Electric Vehicle Infrastructure in New Hampshire*) following an extensive stakeholder process.[31] The most common policy recommendation identified was "approval of reasonable utility make-ready investments as necessary investments in the distribution system and therefore eligible for rate-basing. Make-ready investments include the utility infrastructure just up to the [electric vehicle supply] equipment".[32]

Senate Bill (SB) 575-FN was introduced in 2018, aiming to establish requirements for electric vehicle charging stations. This bill led to the Commission's investigation in IR 20-004 and subsequent docket DE 20-170, both regarding the development of EV TOU rates. UES supported SB 575-FN and testified that further development of electric vehicle infrastructure is essential to meet New Hampshire's environmental and

[30] See Comments of Greenlots in IR 20-004, February 20, 2020; Written Comments of Tesla, Inc. in IR 20-004, July 25, 2020; and Comments of Chargepoint, Inc. in IR 20-004, May 11, 2020 and DE 20-170, January 8, 2021.
[31] "Evaluating Electric Vehicle Infrastructure in New Hampshire." *New Hampshire Department of Business and Economic Affairs*, July 2019, https://www.nh.gov/osi/resource-library/documents/nh-ev-infrastructure-analysis.pdf.
[32] Id. at 2.

transportation goals.[33] The bill received bipartisan support throughout the legislative process and was signed into law by Governor Sununu on June 12, 2018.

In addition to SB 575-FN, another EV bill was passed by the New Hampshire legislature and signed into law by Governor Sununu in 2018, SB 517, *Establishing an Electric Vehicle Charging Stations Infrastructure Commission*.[34] UES also supported SB 517 and was a member of the SB 517 commission ("EV Commission") to provide input to the legislature on how EV infrastructure can be advanced within the state.[35] UES, Eversource, Liberty Utilities, and the New Hampshire Electric Cooperative jointly proposed to support the make-ready work required to install DCFC and Level 2 chargers funded by the VW Settlement Trust.[36] The legislative EV Commission has requested "the electric utilities work with the Public Utilities Commission to design and obtain approval for a 'make ready' program from New Hampshire that is designed to work in conjunction with the RFP and beyond."[37] The NH BEA stakeholder group also supported these investments stating, "New Hampshire utilities have outlined a proposal for investment in DCFC that combines utility investments in make-ready infrastructure with a portion of the Volkswagen Settlement funding. This proposal is widely supported

[33] NH Senate Transportation Committee SB 575-FN, relative to electric vehicle charging stations, January 23, 2018, http://gencourt.state.nh.us/bill_Status/HearingReport.aspx?id=9685&sy=2018.
[34] Senate Bill 517 – Final Version, An Act establishing an electric vehicle charging stations infrastructure commission, May 30, 2018, http://gencourt.state.nh.us/bill_Status/billText.aspx?sy=2018&id=1829&txtFormat=html.
[35] NH Senate Transportation Committee SB 517, establishing an electric vehicle charging stations infrastructure commission, January 30, 2018, http://gencourt.state.nh.us/bill_Status/HearingReport.aspx?id=10182&sy=2018.
[36] NH Electric Vehicle Charging Stations Infrastructure Commission Meeting Minutes, June 28, 2019, https://www.des.nh.gov/sites/g/files/ehbemt341/files/documents/2020-01/20190628-meeting-notes.pdf.
[37] Id. at 2.

by stakeholders surveyed."[38] While the competitive RFP process is still underway for the first phase of this effort, UES will continue to support the development of EV charging in NH and intends to seek recovery of any investments as part of the proposed make-ready program.

V. ELECTRIC VEHICLE (EV) & TIME OF USE (TOU) MARKETING, COMMUNICATIONS AND EDUCATION PLAN

Q. Please describe the Company's MC&E Plan.

A. The Company is proposing a comprehensive, multi-channel MC&E Plan that is designed to meaningfully increase consumer awareness, interest in and adoption of EVs, EV charging infrastructure and EV TOU rates during the initial five years of the EV Program. The MC&E Plan consists of two parts: (1) a Consumer EV Education Campaign (EVs, charging infrastructure, EV/TOU rates); and (2) a Consumer EV Marketing and Promotion Program. The Consumer EV Education Campaign will increase awareness of and inform the Company's customers about the benefits of EVs, new EV and PHEV technologies, available vehicle models, federal and state incentives for vehicle purchases or leases, options for home and public charging, when, where, and how to charge EVs safely, and new EV/TOU rates to encourage customer savings and electric system demand benefit from off-peak charging. The Consumer EV Marketing and Promotion Program will focus on creating experiential learning opportunities for

[38] Id.

customers, partnerships with EV dealerships, and partnerships and incentives/rebates with EV charging infrastructure dealers.

Q. Why does the Company need an education campaign to promote EVs to its customers?

A. In order to help drive the transition to electric transportation and meet Company, federal and state goals, consumers must be educated on the benefits of EVs to create an awareness of and interest in EV ownership. An effective education and outreach initiative can increase the adoption rate for electric vehicles. Of the 71 utilities across the country with active EV adoption strategies/programs, the majority have an integrated education and outreach initiative design to increase awareness of what EVs are and how they work, the difference between plug-in hybrid electric vehicles and battery electric vehicles, the benefit of EV TOU-specific rates, and increase customer understanding of EV charging at home, work, and public locations, and the implications for the customer and the electric system of unmanaged charging. According to the UC Davis International EV Policy Council, although EVs are becoming more popular, "consumer awareness and knowledge of PEVs remains too low in many markets, limiting market growth."[39]

To capitalize on any increased interest in EVs, barriers inhibiting consumers from purchasing an EV should be identified and then countered with educational messaging

[39] "Driving the Market for Plug-in Vehicles: Increasing Consumer Awareness and Knowledge," *UC Davis International EV Policy Council*, March 2018, https://phev.ucdavis.edu/wp-content/uploads/Consumer-Education-Policy-Guide-March-2018.pdf.

that removes these barriers from consideration when customers shop for vehicles. Market research has identified the primary consumer barriers currently inhibiting EV sales as: cost to purchase and maintain an EV; range of travel distance possible on a fully charged battery; limited access to public charging infrastructure; and average time it takes to charge an EV.[40]

The Company's customer communication channels have universal reach throughout our service territory in New Hampshire, and the Company communicates with customers on at least a monthly basis through bills, home energy reports, and regularly through other channels such as email, social media, call center interaction, and direct mailings. The Company currently communicates to customers about energy efficiency products and services, in collaboration with other program administrators under the NHSaves brand. Therefore, the Company proposes to leverage these capabilities and develop a Consumer EV Education Campaign that will educate consumers on the benefits of EVs, the decreasing costs to purchase and maintain an EV, advances made in extending driving range, continued increases in charging station availability, newer charging technologies that greatly reduce EV charging time, and federal and state incentives and rebates for EVs and EV charging infrastructure. The Campaign will also educate customers on EV charging issues such as residential (at home) charging options, when to charge an EV for optimal cost-savings and impact to the electric infrastructure, and how to safely charge an EV. Customers will be educated about the Company's newly proposed suite of EV/TOU

[40] "NESCAUM Multi-State ZEV Action Plan." *NESCAUM*, May 2014, http://www.nescaum.org/documents/multistate-zev-action-plan.pdf/.

rates developed to encourage EV adoption including rates for (a) residential whole-house TOU rate; (b) residential EV TOU rate; (c) small general service EV TOU rate; and (d) large general service EV TOU rate using cost comparison tools that allow customers to compare usage and savings potential.

Q. What are the goals of the Consumer EV Education Campaign to promote EVs?

A. The Consumer EV Education Campaign seeks to increase customer awareness, familiarity, and interest in EVs by making available information about EVs through a mix of utility customer channels, collaborative marketing efforts with other utilities, auto dealers, and EV advocacy groups. Helping customers understand new vehicle types, advances in EV technology, available state and federal incentives, and availability of charging stations and options will increase customers' consideration of EVs and help foster a step change in the way EVs are viewed by the consumer.

Q. Why is the Company interested in customer adoption of EVs?

A. The Company has made a commitment to sustainability to ensure the actions we take today, as a business and as members of our community, deliver long-term value to our customers. The Company must transform our business and provide solutions that advance our region's environmental goals while providing the safe, reliable, affordable service our customers expect. Meeting the Company's environmental goals, as well as federal and state decarbonization targets requires a transformation of the consumer light-duty vehicle market from traditional fossil fuel-based vehicles to EVs. This type of transformation of one of the largest consumer markets in less than a decade requires a collective effort of all stakeholders in the electric vehicle value chain, including New Hampshire car buyers, utilities, automotive manufacturers and dealers, as well as EVSE vendors.

Q. How will the Company know if the Consumer EV Education Campaign is successful?

A. The Company proposes to conduct a consumer awareness study to establish baseline information about our customers' understanding and attitudes toward EVs in order to assess the effect of the education and outreach program and to compare what happens before and after the program has been implemented. Without baseline data, it is difficult to estimate any changes or to demonstrate progress. Following the baseline study, education and outreach efforts can be measured through a mixture of metrics the Company establishes for each education and marketing tactic. The Company will establish milestones for the Campaign and at the end of the education and outreach phase perform qualitative and quantitative analysis (website analysis and social media sentiment and engagement, message testing, surveys) to measure progress versus the baseline study to evaluate the success and efficacy of the Consumer EV Education Campaign.

Specifically, the Company will also measure web traffic to an informational area on the Company website. For any direct email communications to customers, the Company would measure how many customers read (opened) or engaged with an email about EVs, and also track visibility and engagement of its campaign messages on Company social media channels. Initiatives such as these help determine the effectiveness of awareness campaigns. The Company's goal will be to promote its EV benefits messaging to the Company's more than 77,000 New Hampshire electric customers over a five year period. The Company will accomplish this by messaging directly to account holders through their bills and email addresses, and by having messaging about EVs available for customers that are interested when they reach out to our call center. Goals and metrics for each initiative will be developed as part of the campaign design effort.

Q. How will the Company develop the Marketing and Promotion Program and what tactics will it use?

A. The Company will work with internal Communications and Customer Energy Solutions teams, an advertising agency, research firm, and partners to develop campaigns that will:

- Identify and prioritize consumer benefits for EV education
- Identify and prioritize barriers to EV adoption for education and barriers to hosting for business, public site hosts
- Develop multiple messages that highlight benefits, remove barriers, and increase adoption of EVs and EV charging infrastructure and drive EV adoption and participation in the EV TOU rates
- Deliver developed messaging through multiple channels such as:
    - Company-owned
        - Dedicated informational area on Company website
        - Targeted social media advertising (UES Customer Zip codes only)
        - Email campaign (UES Customer Zip codes only)
        - Bill inserts (UES Customers only)

        - Call centers
    - Customer Cost Comparison tool to compare EV TOU rate impact
    - Partner Channels (other utilities, EVSE vendors, and trade groups)
    - Press Coverage (local print, broadcast, and digital media outlets)
    - Purchased Media (advertising: social media advertising, banner ads)
    - EV Events (National Drive Electric Week, and Ride & Drive)
    - EV Manufacturers, Dealer Promotions (Dealerships with New & Pre-Owned EV inventory)
    - EV Advocacy Groups

The Company proposes the above as foundational strategies that will be refined with the advertising agency using data derived from research with input from the partners prior to any campaign launch.

Q. Will the Company work with partners in developing these campaigns?

A. Yes. The Company will first identify and then contract with an external advertising agency and a research firm each with large consumer awareness marketing experience, an understanding of New Hampshire consumers and experience developing messages geared toward sustainability and energy efficiency. Then, the Company will identify and partner with strategic stakeholders in the EV value chain to develop as comprehensive and as aligned an approach as possible to increase campaign effectiveness, expand reach and control costs. Partners may include:

- Other utilities
- EVSE Providers

- Business/Trade Groups/Partnerships/Networking Associations
- Event sponsors

Q. What are the estimated costs of the MC&E Plan?

A. The Company's estimate of the proposed MC&E Plan costs is $370,000 as shown in Exhibit CSV-14.

Q. How did the Company develop the estimated costs for the proposed MC&E Plan?

A. The Company first identified recent, similarly themed and sized awareness and participation campaigns to establish baseline costs of similarly-structured educational campaigns. The Company prioritized leveraging "Company-owned" communications channels and materials (website, social media, email, bill inserts, call center) to maximize efficiency and reduce costs. The Company also researched the cost of available cost comparison tools to provide educated estimates, including required web development and integration. While the final strategy may alter tactics and associated costs, the Company believes the aggregate total that is presented in this filing is what would be necessary to successfully meet the goals put forth in its TOU rate offerings and EV Program.

Q. How will the Company measure effectiveness and cost efficiency?

A. To ensure that its campaign tactics and messaging are effective and cost-efficient, the Company will:

- Perform qualitative and quantitative analyses (site traffic analysis, event attendance, focus groups, sentiment, surveys) at established milestones for the Consumer EV Education Campaign and the Consumer EV Marketing and Promotion Program

- Continue messaging and tactics that are meeting established goals/metrics for each campaign and change or replace those that are not

The most successful campaigns require some refining after launch due to the constantly shifting markets, technological improvements, and competing priorities. The Company anticipates that the initiatives under the MC&E Plan will be no different and would adjust and refocus tactics in response to any anticipated or unanticipated results.

Q. Why does the Company need to promote the benefits of its TOU rates and EV Program to consumers and prospective charging site hosts?

A. To increase EV adoption, the Company must address the barrier concerning at-home EV charging by increasing consumer awareness and understanding of the benefits of residential EV at home charging using smart Level 2 chargers when paired with specifically designed a residential EV TOU rate. The Company is proposing a behind-the-meter EVSE installation and incentive program with up to $600 rebates for 500 customers to drive adoption. Efforts are also needed to increase prospective public charging station site hosts' familiarity with EV charging as an amenity for employees, customers, tenants, or visitors. The Company's make-ready program is designed to address these barriers through simplifying and reducing the cost of installing public EV charging equipment. The MC&E Plan will support the broad marketing of the make-ready program to potential site hosts across the Company's New Hampshire service territory. The Company believes marketing to potential site hosts is essential to the development of EV charging infrastructure in New Hampshire.

Q. Are there other EV related costs the Company is proposing for recovery?

A. Yes, in addition to the make-ready EV infrastructure costs the Company has outlined, the Company proposes to recover the actual and incremental costs associated with the Residential Behind-the-Meter EVSE Installation and Incentive Program and MC&E Plan through the External Delivery Charge ("EDC"). The Company will include an estimate of these costs in the annual EDC filing which would be reconciled to actual costs consistent with the operation of the EDC.

Q. Does this conclude your testimony?

A. Yes it does.

[THIS PAGE INTENTIONALLY LEFT BLANK]

Statewide EV Registrations as of 01/02/2021
Exhibit CSV-2

Town	# of BEV	# of PHEV	# of Unknown	Total EVs 2021
ACWORTH	2	1	0	3
ALBANY	1	2	0	3
ALEXANDRIA	0	3	1	4
ALLENSTOWN	2	3	1	6
ALSTEAD	5	7	1	13
ALTON	13	7	1	21
AMHERST	53	33	2	88
ANDOVER	4	6	1	11
ANTRIM	3	3	0	6
ASHLAND	1	2	1	4
ATKINSON	7	7	4	18
AUBURN	23	7	0	30
BARNSTEAD	1	1	0	2
BARRINGTON	11	11	3	25
BARTLETT	8	1	0	9
BATH	0	1	0	1
BEDFORD	110	48	17	175
BELMONT	5	4	4	13
BENNINGTON	0	2	0	2
BERLIN	0	5	3	8
BETHLEHEM	3	2	1	6
BOSCAWEN	1	5	0	6
BOW	24	20	3	47
BRADFORD	3	0	1	4
BRENTWOOD	15	10	4	29
BRIDGEWATER	6	2	1	9
BRISTOL	2	3	2	7
BROOKLINE	13	10	1	24
CAMPTON	4	10	0	14
CANAAN	3	6	1	10
CANDIA	2	5	0	7
CANTERBURY	5	15	1	21
CARROLL	1	0	1	2
CENTER HARBOR	1	0	0	1
CHARLESTOWN	3	4	1	8
CHESTER	16	4	1	21
CHESTERFIELD	6	10	3	19
CHICHESTER	2	6	1	9
CLAREMONT	4	11	1	16
COLEBROOK	1	0	0	1
CONCORD	51	69	5	125
CONWAY	9	6	2	17
COOS COUNTY TREASU	0	0	1	1

Town	# of BEV	# of PHEV	# of Unknown	Total EVs 2021
CORNISH	1	4	1	6
CROYDON	2	2	1	5
DALTON	2	2	0	4
DANVILLE	6	3	1	10
DEERFIELD	3	9	3	15
DEERING	2	2	0	4
DERRY	36	34	3	73
DORCHESTER	0	1	0	1
DOVER	52	44	5	101
DUBLIN	3	9	0	12
DUMMER	2	1	0	3
DUNBARTON	6	5	0	11
DURHAM	45	39	3	87
EAST KINGSTON	5	7	2	14
EASTON	1	0	0	1
EATON	1	1	1	3
EFFINGHAM	2	1	1	4
ELLSWORTH	1	0	0	1
ENFIELD	11	15	1	27
EPPING	12	8	1	21
EPSOM	3	8	1	12
ERROL	0	0	1	1
EXETER	45	38	5	88
FARMINGTON	3	5	1	9
FITZWILLIAM	2	6	1	9
FRANCESTOWN	1	4	0	5
FRANCONIA	2	2	0	4
FRANKLIN	5	10	0	15
FREEDOM	0	1	0	1
FREMONT	3	6	0	9
GILFORD	19	8	9	36
GILMANTON	2	3	0	5
GILSUM	1	7	1	9
GOFFSTOWN	19	23	4	46
GORHAM	3	1	1	5
GRAFTON	1	0	0	1
GRANTHAM	11	13	1	25
GREENFIELD	3	4	0	7
GREENLAND	11	8	0	19
GREENVILLE	3	1	0	4
GROTON	0	1	0	1
HAMPSTEAD	10	7	1	18
HAMPTON	23	28	2	53
HANCOCK	4	4	0	8
HANOVER	64	43	13	120
HARRISVILLE	1	11	0	12

Town	# of BEV	# of PHEV	# of Unknown	Total EVs 2021
HARTS LOCATION	0	1	0	1
HAVERHILL	0	1	0	1
HEBRON	1	1	3	5
HENNIKER	11	4	0	15
HILL	0	0	1	1
HILLSBORO	0	1	0	1
HINSDALE	1	17	0	18
HOLDERNESS	5	6	0	11
HOLLIS	61	39	1	101
HOOKSETT	21	21	6	48
HOPKINTON	14	16	1	31
HUDSON	45	36	8	89
JACKSON	5	3	0	8
JAFFREY	10	16	3	29
JEFFERSON	0	3	0	3
KEENE	28	84	3	115
KENSINGTON	7	4	1	12
KINGSTON	10	5	0	15
LACONIA	11	16	7	34
LANCASTER	5	7	2	14
LANDAFF	1	0	0	1
LANGDON	2	3	0	5
LEBANON	18	37	1	56
LEE	11	13	2	26
LEMPSTER	1	3	0	4
LINCOLN	5	2	1	8
LISBON	1	5	0	6
LITCHFIELD	6	11	3	20
LITTLETON	3	10	1	14
LONDONDERRY	44	36	5	85
LOUDON	4	5	3	12
LYMAN	0	2	0	2
LYME	18	12	1	31
LYNDEBOROUGH	2	4	0	6
MADBURY	8	6	1	15
MADISON	3	4	0	7
MANCHESTER	95	91	12	198
MARLBOROUGH	0	11	0	11
MARLOW	1	5	0	6
MASON	1	4	0	5
MEREDITH	16	4	0	20
MERRIMACK	50	37	5	92
MIDDLETON	1	2	0	3
MILAN	1	0	0	1
MILFORD	20	18	1	39
MILTON	4	9	0	13

Town	# of BEV	# of PHEV	# of Unknown	Total EVs 2021
MONROE	2	6	0	8
MONT VERNON	9	7	1	17
MOULTONBORO	12	7	5	24
NASHUA	173	137	24	334
NELSON	7	4	0	11
NEW BOSTON	11	5	0	16
NEW CASTLE	16	4	4	24
NEW DURHAM	5	3	0	8
NEW HAMPTON	2	3	4	9
NEW IPSWICH	2	10	1	13
NEW LONDON	22	13	3	38
NEWBURY	7	7	1	15
NEWFIELDS	9	2	1	12
NEWINGTON	3	8	2	13
NEWMARKET	12	17	0	29
NEWPORT	1	8	2	11
NEWTON	4	5	0	9
NORTH HAMPTON	9	5	2	16
NORTHFIELD	4	1	1	6
NORTHUMBERLAND	1	0	0	1
NORTHWOOD	5	10	1	16
NOTTINGHAM	9	5	2	16
ORANGE	1	2	0	3
ORFORD	6	6	0	12
OSSIPEE	1	1	1	3
PELHAM	31	30	9	70
PEMBROKE	9	10	1	20
PETERBOROUGH	21	27	1	49
PIERMONT	1	1	0	2
PITTSBURG	0	1	0	1
PITTSFIELD	1	0	0	1
PLAINFIELD	11	9	3	23
PLAISTOW	7	7	1	15
PLYMOUTH	8	11	1	20
PORTSMOUTH	82	72	9	163
RANDOLPH	2	1	0	3
RAYMOND	9	4	1	14
RICHMOND	0	5	0	5
RINDGE	8	8	1	17
ROCHESTER	21	26	3	50
ROLLINSFORD	8	2	0	10
ROXBURY	1	1	0	2
RUMNEY	0	7	0	7
RYE	40	13	4	57
SALEM	55	32	7	94
SALISBURY	0	2	0	2

Town	# of BEV	# of PHEV	# of Unknown	Total EVs 2021
SANBORNTON	5	7	2	14
SANDOWN	5	2	1	8
SANDWICH	5	2	0	7
SEABROOK	19	10	5	34
SHELBURNE	0	1	0	1
SOMERSWORTH	9	12	1	22
SOUTH HAMPTON	4	4	0	8
SPRINGFIELD	4	6	0	10
STEWARTSTOWN	1	0	0	1
STODDARD	2	4	1	7
STRAFFORD	2	6	0	8
STRATHAM	27	16	2	45
SUGAR HILL	2	4	0	6
SULLIVAN	0	2	0	2
SULLIVAN COUNTY	110	102	22	234
SUNAPEE	9	8	1	18
SURRY	0	1	0	1
SUTTON	2	2	0	4
SWANZEY	6	27	1	34
TAMWORTH	5	5	1	11
TEMPLE	3	2	2	7
THORNTON	2	4	0	6
TILTON	1	3	1	5
TROY	1	4	0	5
TUFTONBORO	4	3	2	9
UNITY	0	1	0	1
WAKEFIELD	3	7	0	10
WALPOLE	9	14	0	23
WARNER	2	8	1	11
WARREN	0	1	0	1
WASHINGTON	3	2	2	7
WATERVILLE VALLEY	5	1	0	6
WEARE	9	8	1	18
WEBSTER	2	1	0	3
WENTWORTH	0	1	0	1
WESTMORELAND	2	6	0	8
WHITEFIELD	1	3	0	4
WILMOT	10	5	1	16
WILTON	14	7	0	21
WINCHESTER	0	10	1	11
WINDHAM	57	35	6	98
WINDSOR	1	0	0	1
WOLFEBORO	8	9	2	19
WOODSTOCK	1	1	4	6
Statewide Totals	2410	2298	362	5070

[THIS PAGE INTENTIONALLY LEFT BLANK]

UES EV Adoption Model 2020-2031
Exhibit CSV-3

Total Registered EV Through 2020	
Capital	248
Seacoast	332
UES Total	**580**

Customer Count	
UES-Capital	30654
UES-Seacoast	47713

General Assumption	
Aggressiveness applied to EEI Projection	100%

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
EEI EV Projection (National)	1,947,370	2,554,186	3,278,421	4,115,521	5,185,763	6,529,197	8,192,743	10,194,411	12,600,697	15,423,574	18,719,480	22,719,697

Town	Total EVs
Capital-Region	
BOSCAWEN	6
BOW	47
CANTERBURY	21
CHICHESTER	9
CONCORD	125
DUNBARTON	11
EPSOM	12
LOUDON	12
SALISBURY	2
WEBSTER	3
Capital-Region Total	**248**
Seacoast-Region	
ATKINSON	18
DANVILLE	10
EAST KINGSTON	14
EXETER	88
HAMPTON	53
HAMPTON FALLS	11
KENSINGTON	12
KINGSTON	15
NEWTON	9
PLAISTOW	15
SEABROOK	34
SOUTH HAMPTON	8
STRATHAM	45
Seacoast-Region Total	**332**
UES Total:	**580**

Note - No Data for Hampton Falls - assumed total based on customer served of seacoast towns
Note - Did not include towns that Unitil serves less than 100 customers

Aggressiveness applied to EEI Projection	100%

EEI EV Projection	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
EVs Nationally	1,947,370	2,554,186	3,278,421	4,115,521	5,185,763	6,529,197	8,192,743	10,194,411	12,600,697	15,423,574	18,719,480	22,719,697
Growth Rate		0.31	0.28	0.26	0.26	0.26	0.25	0.24	0.24	0.22	0.21	0.21

	Registered EVs (baseline)	**UES Projected EV by Year**										
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Capital	248	325	418	524	660	832	1,043	1,298	1,605	1,964	2,384	2,893
Seacoast	332	435	559	702	884	1,113	1,397	1,738	2,148	2,630	3,191	3,873
UES Total	580	761	976	1,226	1,545	1,945	2,440	3,036	3,753	4,594	5,575	6,767

[THIS PAGE INTENTIONALLY LEFT BLANK]

AVAILABILITY

Service is available under this schedule for all domestic purposes, subject to the conditions contained herein at individual private dwellings and farms connected herewith, and in individual apartments, and includes the operation of single phase motors having such characteristics and so operated as not to impair service to other Customers. Single phase motors exceeding five (5) horsepower will be allowed only upon approval by the Company in each instance.

This schedule is available to domestic Customers having uncontrolled (quick recovery) electric water heating equipment only if such equipment has two (2) thermostatically operated heating elements, each with a rating of no more than 5,500 watts, so connected and interlocked that they cannot operate simultaneously.

When service is delivered through one meter and used for both domestic and non-domestic purposes, billing shall be under this Schedule when the predominate use of demand, as determined by the Company, is for domestic purposes.

If electricity is delivered through more than one meter, the charge for electricity delivered through each meter shall be computed separately under this rate. The availability of this rate will be subject to the Company's ability to obtain the necessary meters and to render such service.

This Schedule is not available for service furnished for commercial or business purposes, farms where the maximum demand exceeds 15 kW, motels, hotels and boarding or lodging houses or residences in which three (3) or more rooms are rented, except as specifically provided for under Special Provisions below, or for any other non-residential purposes. This Schedule is not available to net metered customers.

The actual delivery of service and the rendering of bills under this rate is contingent upon the installation of the necessary time-of-use metering equipment by the Company; subject to both the availability of such meters from the Company's supplier and the conversion or installation procedures as established by the Company

CHARACTER OF SERVICE

Electricity will normally be delivered at 120/240 volts using three wire, single phase service. In some areas service may be 120/208 volts, single phase, three wire.

.

CHARGES - MONTHLY

The Delivery Service Charges shall include Distribution Charges and Adjustments, set forth below. The rates for energy (kWh) based charges are seasonal with a winter period from November 1 to April 30 and a summer period from May 1 to October 31.

Rates for Retail Delivery Service Effective May 1, 2021 through October 31, 2021

Customer Charge: $21.07 per meter

Distribution Charge:

Off Peak kWh	4.622¢ per kWh
Mid Peak kWh	4.622¢ per kWh
On Peak kWh	4.622¢ per kWh

External Delivery Charge - Transmission:

Off Peak kWh	0.408¢ per kWh
Mid Peak kWh	4.683¢ per kWh
On Peak kWh	11.567¢ per kWh

Default Service Charge:

Off Peak kWh	6.304¢ per kWh
Mid Peak kWh	7.003¢ per kWh
On Peak kWh	8.594¢ per kWh

Off peak hours will be from 12AM to 6AM and all day holidays and weekends.
Mid peak hours will be from 6AM to 3PM daily Monday through Friday, except holidays.
Peak hours will be from 3PM to 8PM daily Monday through Friday, except holidays.

ADJUSTMENTS

These Adjustments, included in the Delivery Service Charges, shall be adjusted from time to time.

External Delivery Charge (non-transmission): All energy delivered under this Schedule shall be subject to the External Delivery Charge, non-transmission as provided in Schedule EDC of the Tariff of which this is a part.

Stranded Cost Charge: All energy delivered under this Schedule shall be subject to the Stranded Cost Charge as provided in Schedule SCC of the Tariff of which this is a part.

Storm Recovery Adjustment Factor: All energy delivered under this Schedule shall be subject to the Storm Recovery Adjustment Factor as provided in Schedule SRAF of the Tariff of which this is a part.

System Benefits Charge: All energy delivered under this Schedule shall be subject to the System Benefits Charge as provided in Schedule SBC of the Tariff of which this is a part.

Revenue Decoupling Adjustment Charge: All energy delivered under this Schedule shall be subject to the Revenue Decoupling Adjustment Charge as provided in Schedule RDAC of the Tariff of which this is a part.

TERMS OF PAYMENT

The charges for service hereunder are net, billed monthly and due within 25 days following the date postmarked on the bill, as specified in the Terms and Conditions for Distribution Service, which is a part of this Tariff. Amounts not paid prior to the due date shall be subject to interest on past due accounts, as provided in Appendix A of the Terms and Conditions for Distribution Service, and will apply to the unpaid balance. When billing on the OL Schedule is combined with billing on this rate, the interest on past due accounts shall apply to the total bill. The Company will waive the residential late payment fee if the Customer can provide evidence of their eligibility in any of the following programs: Statewide Low-Income Electric Assistance Program (NHPUC Order No. 23,980), Fuel Assistance, Temporary Assistance for Needy Families (TANF), Supplemental Security Income (SSI), Aid to the Permanently and Totally Disabled (APTD), Aid to the Needy Blind (ANB), Old Age Assistance (OAA), Subsidized School Lunch Programs, Title XX Day Care Program, Food Stamps, Medicaid, Subsidized Housing, or Women, Infant and Children Program (WIC).

TERM OF CONTRACT

A customer is eligible to take service on this Schedule upon meeting the qualifications for this Schedule to the satisfaction of the utility and with the consent of the utility. A customer receiving service under this schedule may elect to change to another applicable rate schedule but only after receiving service on this schedule for at least 12 consecutive months. If a customer elects to discontinue service on this schedule, the customer will not be permitted to return to this schedule for a period of one year.

EXTRA SERVICE CHARGES

In addition to the charges for electric service herein specified, additional charges for extra services rendered will be made in accordance with the Tariff which this Schedule is a part.

TARIFF PROVISIONS

The Company's complete Tariff where not inconsistent with any specific provisions hereof, is part of this Schedule.

AVAILABILITY

Service under this schedule is specifically limited to residential customers who require service restricted to charging a battery electric vehicle (BEV) or plug-in hybrid electric vehicle (PHEV) via a recharging outlet at the customer's premises. This schedule is not available to customers with a conventional charge sustaining (battery recharged solely from the vehicle's on-board generator) hybrid electric vehicle (HEV). This Schedule is available for all customers currently taking service or eligible to receive service from Schedule D or Schedule TOU-D.

CHARACTER OF SERVICE

The charging station shall be connected by means of an approved circuit to a separate charging meter for electric vehicles. Electricity will normally be delivered at 120/240 volts using three wire, single phase service. In some areas service may be 120/208 volts, single phase, three wire.

CHARGES – MONTHLY

The Delivery Service Charges shall include Distribution Charges and Adjustments, set forth below. The rates for energy (kWh) based charges are seasonal with a winter period from November 1 to April 30 and a summer period from May 1 to October 31.

Rates for Retail Delivery Service Effective May 1, 2021 through October 31, 2021

Customer Charge $5.26 per meter

Distribution Charge

Off Peak kWh	2.941¢ per kWh
Mid Peak kWh	4.941¢ per kWh
Peak kWh	8.797¢ per kWh

External Delivery Charge - Transmission:

Off Peak kWh	0.408¢ per kWh
Mid Peak kWh	4.683¢ per kWh
Peak kWh	11.567¢ per kWh

Default Service Charge:

Off Peak kWh:	6.304¢	per kWh
Mid Peak kWh	7.003¢	per kWh
Peak kWh	8.594¢	per kWh

Off peak hours will be from 12AM to 6AM and all day holidays and weekends.
Mid peak hours will be from 6AM to 3PM daily Monday through Friday, except holidays.
Peak hours will be from 3PM to 8PM daily Monday through Friday, except holidays.

ADJUSTMENTS

These Adjustments, included in the Delivery Service Charges, shall be adjusted from time to time.

External Delivery Charge (non-transmission): All energy delivered under this Schedule shall be subject to the External Delivery Charge, non-transmission as provided in Schedule EDC of the Tariff of which this is a part.

Stranded Cost Charge: All energy delivered under this Schedule shall be subject to the Stranded Cost Charge as provided in Schedule SCC of the Tariff of which this is a part.

Storm Recovery Adjustment Factor: All energy delivered under this Schedule shall be subject to the Storm Recovery Adjustment Factor as provided in Schedule SRAF of the Tariff of which this is a part.

System Benefits Charge: All energy delivered under this Schedule shall be subject to the System Benefits Charge as provided in Schedule SBC of the Tariff of which this is a part

TERMS OF PAYMENT

The charges for service hereunder are net, billed monthly and due within 25 days following the date postmarked on the bill, as specified in the Terms and Conditions for Distribution Service, which is a part of this Tariff. Amounts not paid prior to the due date shall be subject to interest on past due accounts, as provided in Appendix A of the Terms and Conditions for Distribution Service, and will apply to the unpaid balance. When billing on the OL Schedule is combined with billing on this rate, the interest on past due accounts shall apply to the total bill. The Company will waive the residential late payment fee if the Customer can provide evidence of their eligibility in any of the following programs: Statewide Low-Income Electric Assistance Program (NHPUC Order No. 23,980), Fuel Assistance, Temporary Assistance for Needy Families (TANF), Supplemental Security Income (SSI), Aid to the Permanently and Totally Disabled (APTD), Aid to the Needy Blind (ANB), Old Age Assistance (OAA), Subsidized School Lunch Programs, Title XX Day Care Program, Food Stamps, Medicaid, Subsidized Housing, or Women, Infant and Children Program (WIC).

TERM OF CONTRACT

A customer is eligible to take service on this Schedule upon meeting the qualifications for this Schedule to the satisfaction of the utility and with the consent of the utility. A customer receiving service under this schedule may elect to change to another applicable rate schedule but only after receiving service on this schedule for at least 12 consecutive months. If a customer elects to discontinue service on this schedule, the customer will not be permitted to return to this schedule for a period of one year.

TARIFF PROVISIONS

The Company's complete Tariff where not inconsistent with any specific provisions hereof, is part of this Schedule.

[THIS PAGE INTENTIONALLY LEFT BLANK]

AVAILABILITY

Service under this schedule is specifically limited to customers who require service for charging a battery electric vehicle (BEV) or plug-in hybrid electric vehicle (PHEV) via a recharging outlet at the customer's premises. This Schedule is available for use at business locations or commercially owned electric vehicle charging stations with average use consistently below two-hundred (200) kilovolt-ampere (kVA) of demand and generally less than one-hundred thousand (100,000) kilowatt-hours per month, as measured by the Company.

CHARACTER OF SERVICE

The charging station shall be connected by means of an approved circuit to a separate charging meter for the electric vehicle charging station. Electric service of the following description is available, depending upon the location of the Customer: (1) 120/240 volts, single phase, three wire; (2) 120/208 volts, single phase, three wire; (3) 208Y/120 volts, three phase, four wire; (4) 480Y/277 volts, three phase, four wire; (5) 4160 volts, three phase, four wire or such higher primary distribution voltage as may be available, the voltage to be designated by the Company.

CHARGES - MONTHLY

The Delivery Service Charges shall include Distribution Charges and Adjustments, set forth below. The rates for energy (kWh) based charges are seasonal with a winter period from November 1 to April 30 and a summer period from May 1 to October 31.

Rates for Retail Delivery Service Effective May 1, 2021 through October 31, 2021

Customer Charge	$32.20 per meter
Distribution Demand Charge	$11.59 per kW

External Delivery Charge - Transmission:

Off Peak	0.408¢ per kWh
Mid Peak	3.717¢ per kWh
Peak	14.354¢ per kWh

Default Service Charge

Off Peak	5.278¢ per kWh
Mid Peak	6.035¢ per kWh
Peak	7.378¢ per kWh

Off peak hours will be from 12AM to 6AM and all day holidays and weekends.
Mid peak hours will be from 6AM to 3PM daily Monday through Friday, except holidays.
Peak hours will be from 3PM to 8PM daily Monday through Friday, except holidays.

DEMAND CHARGE DISCOUNT

During the first three years of service, Demand Charges for any new customer will be discounted each year in accordance with the table below.

	1st Year	2nd Year	3rd Year	4th Year
Demand Charge Discount	75%	50%	25%	0%

ADJUSTMENTS

These Adjustments, included in the Delivery Service Charges, shall be adjusted from time to time.

External Delivery Charge (non-transmission): All energy delivered under this Schedule shall be subject to the External Delivery Charge as provided in Schedule EDC of the Tariff of which this is a part.

Stranded Cost Charge: All energy delivered under this Schedule shall be subject to the Stranded Cost Charge as provided in Schedule SCC of the Tariff of which this is a part.

Storm Recovery Adjustment Factor: All energy delivered under this Schedule shall be subject to the Storm Recovery Adjustment Factor as provided in Schedule SRAF of the Tariff of which this is a part.

System Benefits Charge: All energy delivered under this Schedule shall be subject to the System Benefits Charge as provided in Schedule SBC of the Tariff of which this is a part.

DETERMINATION OF DEMAND

The metered demand used for billing shall be the maximum fifteen-minute kilowatt (kW) demand determined during the current month, but in no case less than one kW or the minimum available demand capacity specified by an agreement between the Customer and the Company. The billing demand shall be taken in 0.1 kW intervals, and those demands falling between the intervals shall be billed on the next lower 0.1 kW.

If the Customer's average use is consistently equal to or in excess of two-hundred (200) kilovolt-ampere (kVA) of demand and is generally greater than one-hundred thousand (100,000) kilowatt-hours per month, as measured by the Company, the Customer may be placed on rate TOU-EV-G1.

The Company reserves the right to install kilovolt-ampere meters, and in such case the monthly demand shall not be less than 90% of the measured kVA.

TERMS OF PAYMENT

The charges for service hereunder are net, billed monthly and due within 25 days following the date postmarked on the bill, as specified in the Terms and Conditions for Distribution Service, which is a part of this Tariff.

TERM OF CONTRACT

A customer is eligible to take service on this Schedule upon meeting the qualifications for this Schedule to the satisfaction of the utility and with the consent of the utility. A customer receiving service under this schedule may elect to change to another applicable rate schedule but only after receiving service on this schedule for at least 12 consecutive months. If a customer elects to discontinue service on this schedule, the customer will not be permitted to return to this schedule for a period of one year.

METERING

The Company may at its option meter at the Customer's utilization voltage or on the high tension side of the transformer through which service is furnished.

In the later case, or if the Customer's utilization voltage requires no transformation, and if the Company meters service at 4,160 volts or over, a compensating deduction of 2.0% will be made from the metered kilowatt or kilovolt-ampere demand and metered kilowatt-hour usage to determine billing amounts. If the Company meters service at 34,500 volts or over, a compensating deduction of 3.5% will be made from the metered kilowatt or kilovolt-ampere demand and metered kilowatt-hour usage to determine billing amounts. Demands for these purposes will be as determined under the Determination of Demand provision of this Schedule.

CREDIT FOR TRANSFORMER OWNERSHIP

If the Customer furnishes all transformers which may be required so that the Company is not required to furnish any transformers, there will be credited, against the amount established under the Determination of Demand and Metering provisions of this Schedule, 50 cents for each kilowatt of monthly billing demand, or 50 cents for each kilovolt-ampere of monthly billing demand

MINIMUM CHARGE

The Minimum Charge per month shall be no less than the Customer Charge for each type of service installed plus a capacity charge based upon a minimum demand as defined under the Determination of Demand provision of this Schedule.

TARIFF PROVISIONS

The Company's complete Tariff where not inconsistent with any specific provisions hereof, is part of this Schedule.

AVAILABILITY

Service under this schedule is specifically limited to customers who require service for charging a battery electric vehicle (BEV) or plug-in hybrid electric vehicle (PHEV) via a recharging outlet. This Schedule is available for use at business locations or commercially owned electric vehicle charging stations with average use consistently equal to or in excess of two-hundred (200) kilovolt-ampere (kVA) of demand and is generally greater than one-hundred thousand (100,000) kilowatt-hours per month, as measured by the Company.

CHARACTER OF SERVICE

The charging station shall be connected by means of an approved circuit to a separate charging meter for the electric vehicle charging station. Electric service of the following description is available, depending upon the location of the Customer: (1) 120/240 volts, single phase, three wire; (2) 120/208 volts, single phase, three wire; (3) 208Y/120 volts, three phase, four wire; (4) 480Y/277 volts, three phase, four wire; (5) 4160 volts, three phase, four wire or such higher primary distribution voltage as may be available, the voltage to be designated by the Company.

CHARGES - MONTHLY

The Delivery Service Charges shall include Distribution Charges and Adjustments, set forth below. The rates for energy (kWh) based charges are seasonal with a winter period from November 1 to April 30 and a summer period from May 1 to October 31.

Rates for Retail Delivery Service Effective May 1, 2021 through October 31, 2021

Customer Charge

Secondary Voltage	$178.93	per meter
Primary Voltage	$95.42	per meter

Distribution Demand Charge $8.37 per kVa

External Delivery Charge - Transmission:

Off Peak	0.408¢	per kWh
Mid Peak	3.867¢	per kWh
Peak	14.117¢	per kWh

Off peak hours will be from 12AM to 6AM and all day holidays and weekends.
Mid peak hours will be from 6AM to 3PM daily Monday through Friday.
Peak hours will be from 3PM to 8PM daily Monday through Friday, except holidays.
.

DEMAND CHARGE DISCOUNT

During the first three years of service, Demand Charges for any new customer will be discounted each year in accordance with the table below.

	1st Year	2nd Year	3rd Year	4th Year
Demand Charge Discount	75%	50%	25%	0%

ADJUSTMENTS

These Adjustments, included in the Delivery Service Charges, shall be adjusted from time to time.

External Delivery Charge (non-transmission): All energy delivered under this Schedule shall be subject to the External Delivery Charge as provided in Schedule EDC of the Tariff of which this is a part.

Stranded Cost Charge: All energy delivered under this Schedule shall be subject to the Stranded Cost Charge as provided in Schedule SCC of the Tariff of which this is a part.

Storm Recovery Adjustment Factor: All energy delivered under this Schedule shall be subject to the Storm Recovery Adjustment Factor as provided in Schedule SRAF of the Tariff of which this is a part.

System Benefits Charge: All energy delivered under this Schedule shall be subject to the System Benefits Charge as provided in Schedule SBC of the Tariff of which this is a part.

DETERMINATION OF DEMAND

For the purpose of demand billing under the Large General Service Schedule G1, metered demands shall be measured as the highest 15-minute integrated kilovolt-ampere (kVA) demand determined during the current month for which the bill is rendered. The monthly billing demand charge shall be based upon this metered demand except that it shall not be less than 80% of the highest demand in any of the immediately preceding eleven months, and in no event shall such demand be taken or considered as being less than 50 kVA.

MINIMUM CHARGE

The Minimum Charge per month shall be no less than the Customer Charge for each type of service installed plus a capacity charge based upon a minimum demand and/or demand ratchet as defined under the Determination of Demand provision of this Schedule.

TERMS OF PAYMENT

The charges for service hereunder are net, billed monthly and due within 25 days following the date postmarked on the bill, as specified in the Terms and Conditions for Distribution Service, which is a part of this Tariff. Amounts not paid prior to the due date shall be subject to interest on past due accounts, as provided in Appendix A of the Terms and Conditions for Distribution Service, and will apply to the unpaid balance. When billing on the OL Schedule is combined with billing on this rate, the interest on past due accounts shall apply to the total bill.

TERM OF CONTRACT

A customer is eligible to take service on this Schedule upon meeting the qualifications for this Schedule to the satisfaction of the utility and with the consent of the utility. A customer receiving service under this schedule may elect to change to another applicable rate schedule but only after receiving service on this schedule for at least 12 consecutive months. If a customer elects to discontinue service on this schedule, the customer will not be permitted to return to this schedule for a period of one year.

METERING

The Company may at its option meter at the Customer's utilization voltage or on the high tension side of the transformer through which service is furnished.

In the later case, or if the Customer's utilization voltage requires no transformation, and if the Company meters service at 4,160 volts or over, a compensating deduction of 2.0% will be made from the metered kilowatt or kilovolt-ampere demand and metered kilowatt-hour usage to determine billing amounts. If the Company meters service at 34,500 volts or over, a compensating deduction of 3.5% will be made from the metered kilowatt or kilovolt-ampere demand and metered kilowatt-hour usage to determine billing amounts. Demands for these purposes will be as determined under the Determination of Demand provision of this Schedule.

CREDIT FOR TRANSFORMER OWNERSHIP

If the Customer furnishes all transformers which may be required so that the Company is not required to furnish any transformers, there will be credited, against the amount established under the Determination of Demand and Metering provisions of this Schedule, 50 cents for each kilowatt of monthly billing demand, or 50 cents for each kilovolt-ampere of monthly billing demand

TARIFF PROVISIONS

The Company's complete Tariff where not inconsistent with any specific provisions hereof, is part of this Schedule.

UES EV TOU Service Requirements

Domestic EV TOU (TOU-EV-D)

Residential customers, who request to participate in the electric vehicle (EV) time of use (TOU) rate program (TOU-EV-D), will have their current load and service conditions reviewed and evaluated by UES (or "the Company") to determine if the existing utility facilities can accommodate the addition of the proposed EV charging.

The field review will determine whether the capability of the existing service is rated for a minimum of 200 amps from the pole to the weather head where overhead ("OH"), or to the meter where underground ("URD").

In the event the existing service is rated for the additional load, the customer will coordinate with the Company for an additional customer-supplied and installed meter socket to accommodate the required UES-provided metering for EV charging. Depending on the installation, the customer may be required to provide and install a multi-gang meter socket. All equipment, installation and methodology of the meter socket installation shall meet Company and National Electric Code ("NEC") standards and specifications in affect at the time of the EV charger installation.

Should the customer's existing service not meet the threshold requirements outlined above and a service upgrade is required, such upgrades will be coordinated in accordance with existing service terms and conditions for distribution service. For an OH service installation, the Company will provide, at no direct cost, a new appropriately sized service drop. Where the existing installation is a URD service connected by a conduit system or a URD service fed with direct buried cable, the Company would replace the cable in accordance with existing terms and conditions for distribution service.

The Customer shall be responsible for the provision, installation, excavation and grading required to facilitate the installation as well as any associated structures that may be required to complete the installation.

For any of the above scenarios, should the utility transformer serving the impacted property require additional capacity, the Company will provide an appropriately sized transformer, ancillary equipment and associated labor to complete the service.

For all underground services, the customer will also be required to provide and install a multi-gang meter socket to accommodate the Company supplied meter. All equipment, installation and methodology of the conduit systems and meter socket installation shall meet both Company and NEC standards and specifications in affect at the time of the installation.

Once the meter socket and associated equipment installation is complete and approved by the local authorities having jurisdiction, the Company will install the metering required to monitor the EV charger and the customer will then be eligible for the TOU-EV-D rate.

Small General Service EV TOU (TOU-EV-G2)

Commercial and industrial customers who routinely consume less than 200 kVa and 100,000 kWh per billing month for EV charging only will be eligible for the TOU-EV-G2 rate. Their services, termed secondary services, may be delivered from single, banked or networked transformers that may or may not require current transformers (CTs) to meter their accounts. The methodology of service delivery may vary considerably within this customer class.

Eligible customers who request to participate in TOU-EV-G2 rate program will have their load and service conditions reviewed and evaluated by UES to determine if the existing utility facilities can accommodate the addition of the proposed EV charging.

Due to the range of equipment and installations to provide services to these customers, the Company anticipates working closely with customers to coordinate the installation of the customer-supplied meter socket required to accommodate the Company-supplied metering equipment. The installation, equipment and methodology must meet Company and NEC requirements that are in effect at the time of the installation or service modifications.

Once the metering installation is completed, providing a dedicated meter socket to monitor the EV charging equipment, the customer will then be eligible for TOU-EV-G2 rate.

Large General Service EV TOU (TOU-EV-G1)

Commercial and industrial customers that have a monthly demand in excess of 200 kVa and 100,000 kWh per billing month for EV charging only will be eligible for the TOU-EV-G1 rate. Typically, such customers are served from individual transformers and are classified as “transformer-rated,” equipped with CT cabinets which provide for remote metering equipment. The installation of such stand-alone EV charging shall require the installation of a separate, individual meter socket for monitoring the EV charging equipment by a Company-supplied meter.

Eligible customers who request to participate in the TOU-EV-G1 rate program will have their current load and service conditions reviewed and evaluated by UES to determine if the existing utility facilities can accommodate the addition of the proposed EV charging.

Due to the range of equipment and installations to provide services to these customers, the Company anticipates working closely with customers to coordinate the installation of the customer-supplied meter socket required to accommodate the Company-supplied metering equipment. The installation, equipment and methodology must meet Company and NEC requirements that are in effect at the time of the installation or service modifications.

Once the metering installation is completed, providing a dedicated meter socket to monitor the EV charging equipment, the customer will then be eligible for TOU-EV-G1 rate.

Exhibit CSV-9
EERS Granite State Test BCR for Behind-the-Meter EVSE Installation and Incentive Program (Illustrative Model)

Program Cost-Effectiveness - 2021 PLAN

	nefit/Cost Rat	Benefits ($000)						
	Granite State Test	**Granite State Test**	**Utility Costs ($000 - 2021$)[2]**	**Customer Costs ($000 - 2021$)[2]**	**Annual MWh Savings**	**Lifetime MWh Savings**	**Winter kW Savings**	**Summer kW Savings**
Residential Programs								
B1 - Home Energy Assistance	-	-	-	-	-	-	-	-
A1 - Energy Star Homes	-	-	-	-	-	-	-	-
A2 - Home Performance with Energy Star	-	-	-	-	-	-	-	-
A3 - Energy Star Products	2.18	653.975	300.000	-	25.0	250.0	250.0	250.0
A4 - Residential Behavior	-	-	-	-	-	-	-	-
A5 - Residential Active Demand Response	-							
A6b - Res ISO Forward Capacity Market Expenses	-	-	-	-	-	-	-	-
A6c - Res Education	-	-		-	-	-	-	-
A6d - Energy Optimization Pilot	-	-		-	-	-	-	-
Sub-Total Residential	**2.18**	**653.975**	**300.000**	**-**	**25.0**	**250.0**	**250.0**	**250.0**
Commercial, Industrial & Municipal								
C1 - Large Business Energy Solutions	-	-	-	-	-	-	-	-
C2 - Small Business Energy Solutions	-	-	-	-	-	-	-	-
C3 - Municipal Energy Solutions	-	-	-	-	-	-	-	-
C5 - C&I Active Demand Response	-			-	-	-	-	-
C6b - C&I ISO Forward Capacity Market Expenses	-	-	-	-	-	-	-	-
C6c - C&I Education	-	-	-	-	-	-	-	-
Sub-Total Commercial & Industrial	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	-	-	-	-	-	-	-	-
Total	**2.18**	**653.975**	**300.000**	**-**	**25.0**	**250.0**	**250.0**	**250.0**

Notes:

[THIS PAGE INTENTIONALLY LEFT BLANK]

Description of Electric Vehicle (EV) Make-Ready Service Requirements

The UES Make-Ready Public EV Infrastructure Program is designed to reduce or remove barriers to initiating and installing EV charging stations at publically-available locations. The program consists of utility-supported facilities that will provide the appropriate alternating current ("AC") infrastructure for the installation of charging stations and supporting equipment. Though the make-ready program is generally foreseen to be implemented in three primary scenarios as discussed below, the Company will engage with customers to evaluate other potential installations and deployment of EV charging infrastructure. Electric vehicle supply equipment (EVSE) and any direct current (DC) equipment, as applicable, will be provided by participating customers.

Installation Scenarios

There are principally two major types of equipment for charging – Level 2 chargers which AC output at 240 volts up to 19.2 kW and DC fast chargers ("DCFC") which provide a DC output directly to EVs.

The proposed facilities are designed to support both types of chargers in various configurations. Each description provides an outline of equipment, materials and services from the relative primary utility facilities into the location of the EVSE. All equipment, whether provided by the Company or customer, shall be installed according to Company standards.

Scenario 1 - Level 2 Chargers (up to 10) Served from Overhead (OH) Utility Facilities

This service design would provide for a three phase, 120/208 volt electric service that begins with the replacement of the mainline street pole or the installation of a mid-span street pole to facilitate a tap on the Company's primary system. The tap will consist of overcurrent protective devices (cutouts) and the appropriately sized conductor to extend one span, not to exceed 200', to a service pole which will be equipped with three pole-mounted transformers of the appropriate size.

An underground ("URD") service will be installed from the transformers to a specifically-designed weather resistant cabinet, mounted on a concrete footing. Traditional utility services would end at this point; however, the program will provide the cabinet to accept the URD service lateral and contain the required utility metering, a service-rated distribution panel equipped with a main breaker/disconnect and the necessary size and quantity of circuit breakers to serve the charging facilities.

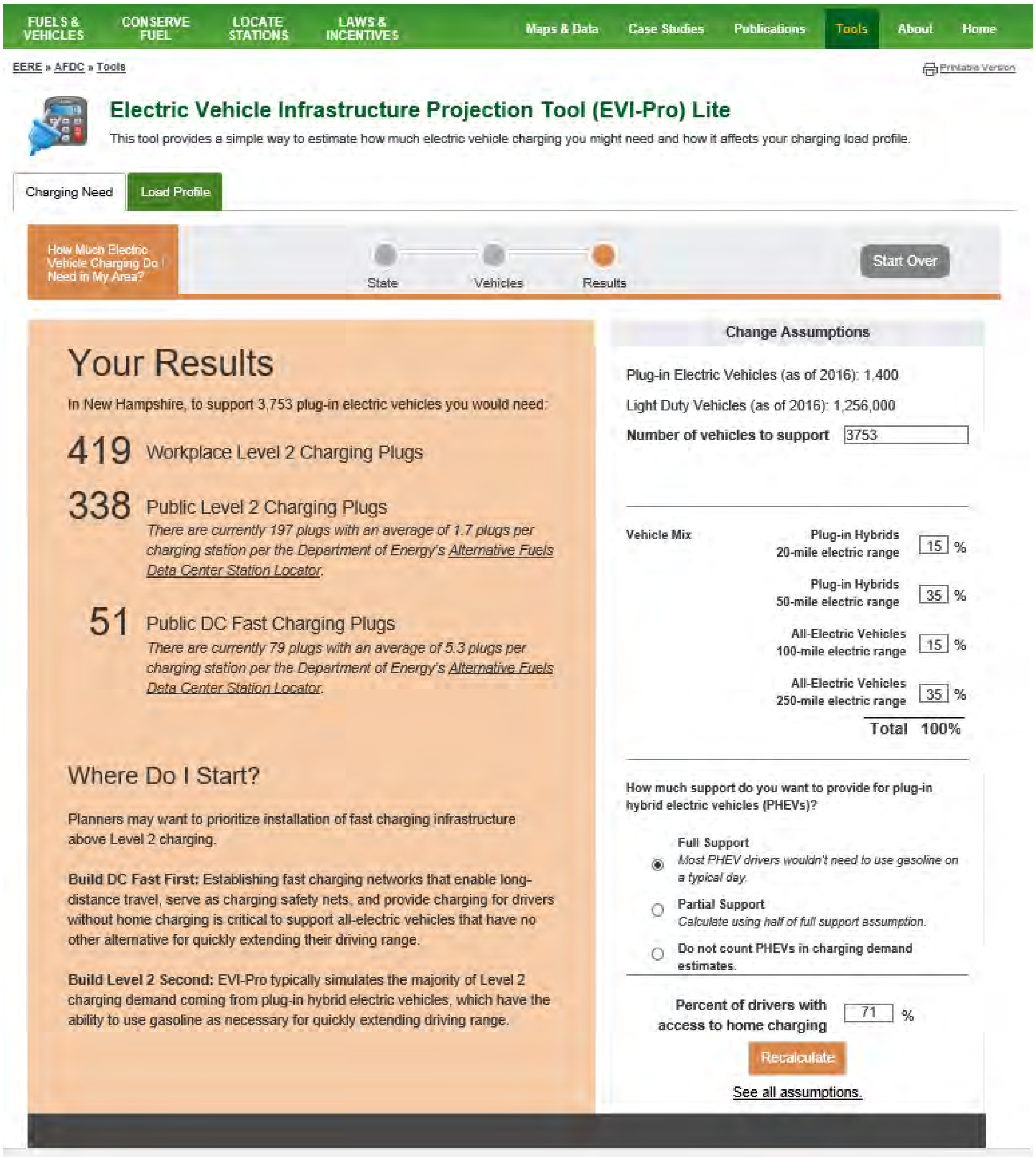
The program provides for the installation of the required conduits to each of the pedestal locations where concrete footings will be provided for the installation of the EVSE. The appropriate branch circuit wiring will also be provided from the service cabinet to the individual kiosk locations for the connection of the EVSE. All excavation and rough grading will be provided as part of the program.

Scenario 2 - Level 2 Chargers (up to 10) Served from URD Utility Facilities

This installation, designed to provide a three phase 120/208 volt service, includes replacement of the mainline pole or installation of a mid-span pole to facilitate a tap from the utility primary system, equipped with "cutouts", to a utility pole located no more than 175' from the mainline/mid-span pole. A primary voltage loop cable system with cutouts will be installed to provide the transition from OH facilities to underground and extended underground, no more than 750' to a transformer pad located within 200' of the location of the charging facility location. A pull box will be installed no more than 250' away from the riser pole to facilitate the installation of the cabling in the primary underground conduit system. The appropriately-sized transformer will be installed on a supplied pad and the secondary conductors will be run in conduit to the service cabinet providing metering, the distribution panel with a main breaker and the appropriately sized branch circuit breakers for the charging facility. The branch circuit conduits and wiring will be installed to the individual charging facility pads to facilitate the wiring of the EVSE. Excavation, footings and grading will be provided.

Scenario 3 - DCFC Served from URD Utility Facilities

Due to the capacity required to serve the DCFC, URD is the only option provided. Installation will provide a pad mounted transformer with 277/480 volt secondary appropriately sized. OH construction will include: 175' from mainline to riser pole, a primary loop feed with cable and conduit not to exceed 750' from riser pole to transformer pad and pull box no more than 250' from riser pole, supplied transformer pad, secondary conduit and cabling, the switchgear, branch circuit conduit and wiring, excavation, grading, and footings/pads. The applicable customer will be responsible for the procurement and installation of all items on the DC-side of the installation including but not limited to the AC/DC converters, conduit, wiring, footings/pads, excavation, grading etc.



FUELS & VEHICLES | CONSERVE FUEL | LOCATE STATIONS | LAWS & INCENTIVES | Maps & Data | Case Studies | Publications | Tools | About | Home

EERE » AFDC » Tools

Printable Version

Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite

This tool provides a simple way to estimate how much electric vehicle charging you might need and how it affects your charging load profile.

Charging Need | Load Profile

How Much Electric Vehicle Charging Do I Need in My Area?

State | Vehicles | Results

Start Over

Your Results

In New Hampshire, to support 3,753 plug-in electric vehicles you would need:

419 Workplace Level 2 Charging Plugs

338 Public Level 2 Charging Plugs

There are currently 197 plugs with an average of 1.7 plugs per charging station per the Department of Energy's Alternative Fuels Data Center Station Locator.

51 Public DC Fast Charging Plugs

There are currently 79 plugs with an average of 5.3 plugs per charging station per the Department of Energy's Alternative Fuels Data Center Station Locator.

Where Do I Start?

Planners may want to prioritize installation of fast charging infrastructure above Level 2 charging.

Build DC Fast First: Establishing fast charging networks that enable long-distance travel, serve as charging safety nets, and provide charging for drivers without home charging is critical to support all-electric vehicles that have no other alternative for quickly extending their driving range.

Build Level 2 Second: EVI-Pro typically simulates the majority of Level 2 charging demand coming from plug-in hybrid electric vehicles, which have the ability to use gasoline as necessary for quickly extending driving range.

Change Assumptions

Plug-in Electric Vehicles (as of 2016): 1,400

Light Duty Vehicles (as of 2016): 1,256,000

Number of vehicles to support 3753

Vehicle Mix

Plug-in Hybrids 20-mile electric range	15	%
Plug-in Hybrids 50-mile electric range	35	%
All-Electric Vehicles 100-mile electric range	15	%
All-Electric Vehicles 250-mile electric range	35	%
Total	100%	

How much support do you want to provide for plug-in hybrid electric vehicles (PHEVs)?

- (•) Full Support *Most PHEV drivers wouldn't need to use gasoline on a typical day.*
- ( ) Partial Support *Calculate using half of full support assumption.*
- ( ) Do not count PHEVs in charging demand estimates.

Percent of drivers with access to home charging 71 %

Recalculate

See all assumptions.

U.S. Department of Energy, Alternative Fuels Data Center, Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite
https://afdc.energy.gov/evi-pro-lite

NH owner-occupied housing rate 2015-2019, U.S. Census Bureau = 71%
https://www.census.gov/quickfacts/fact/table/NH/PST045219

[THIS PAGE INTENTIONALLY LEFT BLANK]

Exhibit CSV-12

UES Budgetary Model for Make-Ready

Level 2 - 19.2 kW EV chargers, 5 chargers for 96 kW total connected load

Equipment	Quantity(ft)	Cost/Unit($/ft)	Cost/Item($)
120/208V distribution enclosure	1		$6,000
4" PVC Conduit	100	3	300
2" PVC Conduit	460	1.45	667
500KCMIL Copper	900	8.52	7668
#2 GND Copper	120	1.6	192
#6 Copper	2400	0.65	1560
#8 GND Copper	1200	0.4	480
Civil Foundation(Xfmr, distribution Panel, chargers)(Materials Include Concrete, Rebar and backfill)			2000
		Total Equipment Cost	$16,867

Labor	Description
$3,000.00	Install all Electrical equipment and Cable
$2,500.00	Excavate and install Conduit ($25.00 PF)
$6,900.00	Excavate and install Conduit ($15.00 PF)
$2,000.00	Excavate, form and pour concrete
$14,400.00	Site Work Total
$45,876.00	Unitil Primary Line Work
$16,867.00	Total Equipment Cost
$77,143.00	**Level 2 Total**

DCFC - 50 kW EV chargers, 6 chargers for 300 kW total connected load

Equipment	Quantity(ft)	Cost/Unit($/ft)	Cost/Item($)
120/208V distribution enclosure	1		$11,000
4" PVC Conduit	200	3	600
2" PVC Conduit	720	1.45	1044
500KCMIL Copper	1800	8.52	15336
#2 GND Copper	900	1.6	1440
#6 Copper	2800	0.65	1820
#8 GND Copper	1400	0.4	560
Civil Foundation(Xfmr, distribution Panel, chargers)(Materials Include Concrete, Rebar and backfill)			3000
Precast Transformer vault & pad		1	4000
5"Primary Conduit	500	10	5000
		Total Equipment Cost	$43,800

Labor	Description
$5,000.00	Install all Electrical equipment and Cable
$6,000.00	Excavate and install Conduit ($25.00 PF)
$10,800.00	Excavate and install Conduit ($15.00 PF)
$4,000.00	Excavate, form and pour concrete. Install precast Transformer vault and pad
$12,500.00	Primary conduit installation
$38,300.00	Site Work Total
$61,294.00	Unitil Primary Line Work
$43,800.00	Total Equipment Cost
$143,394.00	**DCFC Total**

[THIS PAGE INTENTIONALLY LEFT BLANK]

yes
no

Unitil - UES
Customer Project Evaluation & Determination of Non-Refundable Customer Contribution

Note: User Inputs are within Blue highlight cells

Docket No. DE 21-030
Exhibit CSV-13
<<Page 1 of 1>>

Exhibit CSV-13: UES Make-Ready DCF Analysis		
Public Level 2 - 5 Chargers / 10 plugs ($77k) per site	**77,000**	**37x10=370**
Public DCFC - 6 Chargers / 6 plugs ($143k) per site	**143,000**	**8x6=48**
Load per charger = 19.2 kW for Level 2 and 50kW for DCFC		

Project Inputs:

Relative Year	*-*	*1*	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	
Absolute Year	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**Total**
Total Project Cost (before any customer contrib)	*Model accepts multi-year phase-in of capital project costs; Enter as Positive Amounts.*										
(on incremental basis = excl Gen Constr OH's)	$ 231,000	$ 748,000	$ 902,000	$ 979,000	$ 1,133,000	$ -	$ -	$ -	$ -	$ -	$ 3,993,000

Incremental Number of Meters by Year:	**Class**											**Total**
(1) Primary Class/Meters added per Year	03 G2	3	6	8	9	11						37
(2) Add'l Class/Meters added per Year	07 G1	-	2	2	2	2						8
(3) Add'l Class/Meters added per Year	01 D											-
												45

		Hi-Volt	Transform	Historical Average		Annual Average	
		Metering	Ownership	Billed	Billed	Billed	Billed
Average Consumption & Demand		Discount?	Credit?	kWh	Demand	kWh	Demand
(1) Primary Class/Meters added per Year	03 G2	no	no	31,384	122	67,277	1,152
(2) Add'l Class/Meters added per Year	07 G1	no	no	2,154,514	6,409	341,640	3,600
(3) Add'l Class/Meters added per Year	01 D	no	no	7,475	-		-

(As a 'default', model provides - by class - avg consumption and demand per meter based on prior five years)
If known, actual project estimates should be substituted for these historic averages
Model accepts up to three different classes within one 'project'.

Optional Calculation of Consumption and Demands

(If this module is utilized, manually input these calculated demand/kwh values into input table above)		Connected Load kW	Utilization Factor %	Avg Peak Demand kW (mth)	Annual Demand kW	Power Factor %	Avg Peak Demand kVa (mth)	Annual Demand kVa	Load Factor %	Annual Consumpt kWh
(1) Primary Class/Meters added per Year	03 G2	96	100%	96	1,152	100%	96	1,152	8%	67,277
(2) Add'l Class/Meters added per Year	07 G1	300	100%	300	3,600	100%	300	3,600	13%	341,640
(3) Add'l Class/Meters added per Year	01 D			-	-	100%	-	-		-

Solve for Required Customer Contribution

Run the Model with No Customer Contribution
(for 'benchmark' dynamic analytic periods
ending 10 or 20 years beyond year of last capital expenditure)

Run Dynamic 10-Yr Analysis with No CustomerContribution

Run Dynamic 20-Yr Analysis with No Customer Contribution

If IRR/NPV results are below benchmarks:
Re-Run the model to determine the
required non-refundable customer contribution

Run Dynamic 10-Yr Analysis Solve for CustomerContribution

Run Dynamic 20-Yr Analysis Solve for Customer Contribution

	Dynamic 10-Yr (C&I) Analysis			Dynamic 20-Yr (Res) Analysis		
	Results	**Benchmark**	**Flag**	**Results**	**Benchmark**	**Flag**
Total Analysis Years	14			24		
Non-Refundable Customer Contribution	$ -			$ -		
Customer Contribution Payment Plan Option						
Select Payment Plan Length (Months)	0 Months			0 Months		
Monthly Payment Required	$ -			$ -		
IRR on Net Cash Flow (Excl Financing)	8.86%	7.18%	*OK*	13.30%	7.18%	*OK*
Net Present Value - at AftTax WACC	$ 243,869		*OK*	$ 1,522,146		*OK*
Net Company Capital Expenditure	$ 3,993,000			$ 3,993,000		
Simple Payback within relative year ==>	10			10		

Customer Contribution Requirements via Alternative Static Analysis Periods

Time periods reflect relative years identified above and do not begin with the year after the last capital expenditure

	Static 5 yr	Static 10 yr	Static 15 yr	Static 20 yr	Static 25 yr
Non-Refundable Customer Contrib	$ -	$ -	$ -	$ -	$ -
IRR on Net Cash Flow (Excl Financing)		1.39%	9.81%	12.44%	13.44%
Net Present Value - at AftTax WACC	$ (1,889,012)	$ (549,856)	$ 413,106	$ 1,116,476	$ 1,604,401
Net Company Capital Expenditure	$ 3,993,000	$ 3,993,000	$ 3,993,000	$ 3,993,000	$ 3,993,000
Simple Payback within year==>	10	10	10	10	10

(Note: Project acceptance using analysis period
other than dynamic 10-year for C&I or 20-year for Residential requires CFO approval)

[THIS PAGE INTENTIONALLY LEFT BLANK]

UES MC&E Plan Cost Analysis
Exhibit CSV-14

Cost Category	**Estimated Cost**
Market Research/Survey	$30,000.00
Messaging/Design - Integrated Campaign	$15,000.00
Website - Micro site w/ embedded cost calculator tool	$15,000.00
Video/animation	$12,500.00
Rate comparison tool w/ shadow billing	$169,000.00
Social Advertising	$25,000.00
Direct Mail - print + postage	$85,000.00
Bill Insert(s) - print	$15,000.00
Flyers - production	$3,500.00
	$370,000.00

[THIS PAGE INTENTIONALLY LEFT BLANK]

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY

OF

MARK A. LAMBERT

EXHIBIT MAL-1

New Hampshire Public Utilities Commission

Docket No. DE 21-030

Table of Contents

I. INTRODUCTION

Q. Mr. Lambert, what is your position and what are your responsibilities?

A. I am the Vice President, Customer Operations for Unitil Service Corp. ("Unitil Service" or the "Company"). Unitil Service provides, at cost, a variety of administrative and professional services, including regulatory, financial, accounting, human resources, engineering, operations, technology and energy supply management services on a centralized basis to its affiliated Unitil companies,[1] including Unitil Energy Systems, Inc. ("UES"). My responsibilities include the development, execution and operations leadership for the five customer functions provided to the utility operating companies: Customer Solutions, Quality Assurance, Accounts Receivables, Customer Billing, Regulatory Rate Compliance and Customer Revenue Reconciliation.

Q. Please describe your business and educational background.

A. I earned a Bachelor of Science degree in Business Administration Management from Plymouth State University in 1987. Following graduation, I was employed with United Parcel Service ("UPS"), working in various customer service managerial roles. I joined Unitil Service in August of 1997 as the Manager of Customer Service before being promoted to Director of Customer Services in January 2000. In January 2011, I was provided with the opportunity to head up the Company's government affairs area as the

[1] The "Unitil companies" include Unitil Service and its regulated affiliates, UES, Northern Utilities, Inc., and Fitchburg Gas and Electric Light Company, all of which are wholly-owned subsidiaries of Unitil Corporation.

Director, Government Affairs. Finally after receiving additional responsibilities in the Customer Services area in 2017, I assumed the role of Vice President, Customer Operations in January, 2018.

Q. Have you previously testified before the Commission or any other Regulatory agencies?

A. Yes, I have testified before the Commission in previous rate case proceedings, numerous dockets and also in Unitil Corporation's proceeding regarding the acquisition of Northern Utilities, Inc. in 2008. I have also testified before the Massachusetts Department of Public Utilities and the Maine Public Utilities Commission on previous occasions in various proceedings.

Q. What is the purpose of your testimony?

A. I discuss the Company's Customer Information System ("CIS") that was implemented in July 2017 and the need to replace the Company's legacy CIS system, which had been in service for more than twenty two years. I also discuss proposed changes to the Company's Terms and Conditions for Distribution Service.

II. CUSTOMER INFORMATION SYSTEM

Q. **Why did Unitil Service decide to implement a new CIS?**

A. Unitil Service's legacy CIS ("HTE") was implemented over a period of years from 1995 to 1998. Over the next two decades, the energy industry changed rapidly as more complex energy delivery and supply options were made available to gas and electric customers and the technological avenues of communications with customers continued to evolve. As a result, HTE became functionally obsolete and unable to continue to meet current customer needs and expectations, the complexities of the Unitil companies' business, and evolving regulatory requirements.

Q. Please explain how Unitil Service's CIS contributes to the Unitil companies' ability to provide safe, reasonable and adequate service to its customers.

A. The importance of the CIS to a modern utility's provision of service is difficult to overstate. The CIS serves as the core of all of the Unitil companies' business systems and plays a functional role in nearly every aspect of the delivery of service to customers. The critical functional requirements for the CIS include, but are not limited to:

- Customer Billing and Revenue Recognition
- Cash Remittance, Cash Application and Payment Processing
- Regulatory Tariff and Rate Management
- Financial Reporting into the General Ledger
- Metering Validation and Editing
- Credit and Collections
- New Customer Intake and Service Work Orders
- Customer Communications and Customer Service
- Customer Account Portal Web Interface
- Retail Choice and Supplier Billing / Rates; and
- Future-looking Metering / Billing / Rate requirements.

Q. Please describe the CIS project in more detail.

A. This project was a major and critical system-wide conversion that included not only a new CIS, but also a Meter Data Management System ("MDMS"), a new "MyUnitil" customer portal, and 34 individual sub-system interfaces required to operate the CIS environments. The CIS was developed and tested over a period of six years and successfully launched into production across Unitil Corporation's footprint in July 2017. Unitil Service has continued to implement additional functionality in the "post go-live" periods of late 2017 and throughout 2018 and 2019.

Q. Did Unitil Service consider making improvements to its legacy CIS?

A. Unitil Service concluded that updating or improving HTE was not a viable option. As discussed above, HTE was unable to keep pace with the Unitil companies' needs. Moreover, in May 2010, SunGuard (the vendor of HTE) announced the application to be end-of-life. Prior communications from the vendor had indicated a sunset date of five years after such notification, which meant that by 2015 SunGuard would no longer support HTE.

Q. What process did Unitil Service undertake to procure a new CIS?

A. After the project team determined the scope of the CIS functionality, as discussed above, it worked with a consultant, Black & Veatch, to prepare a robust request for proposals ("RFP") to solicit proposals for the new CIS. The RFP was distributed to fifteen different CIS vendors and two MDMS vendors in late May 2012. Unitil Service received nine written proposals in response to the RFP.

Unitil Service, with the assistance of Black & Veatch, conducted a comprehensive evaluation of the proposals that were received.

Q. Did Unitil Service move forward with a CIS vendor based on its evaluation?

A. Yes. At the conclusion of the comprehensive evaluation process it was recommended that the Company move forward with Harris Computers' subsidiary Systems & Software's ("S&S") enQuesta CIS product. In addition to submitting a proposal that met Unitil Service's needs, S&S was an attractive vendor for the CIS project for a variety of reasons. S&S's Harris affiliate, SmartWorks, had already developed a MDMS (MeterSense) that interfaced with the enQuesta CIS, and there were efficiency advantages to working with Harris companies for both CIS and MDMS.

Q. After S&S was selected as the CIS vendor, how did the development of the new CIS proceed?

A. S&S commenced the project initiation in mid-April 2013 and completed that process in early June 2013. Unitil Service signed a contract with S&S on May 1, 2013 and the design process commenced in early June 2013 with the discovery phase. The goal of the discovery phase was to understand the "as-is" state of the Unitil companies' systems and to aggregate existing documentation, procedures, reports, and other artifacts, as well as document business processes. As part of this phase, in-depth review meetings were organized by each functional business area to solicit discovery feedback. The discovery phase was followed by a series of business process analysis workshops, which produced approximately 70 business process and requirement documents that detailed the configuration of the new CIS and requirements for the upgrades to the related information systems.

Q. Was S&S's CIS implementation monitored throughout the process?

A. Yes. Although S&S served as the implementer during the early stages of the project, Unitil Service actively monitored the CIS implementation. In March 2015, Company management determined that a review of the project should be conducted as a result of unexpected delays during the early part of the build phase. The review was performed by Grant Thornton, one of the nation's leading independent audit, tax and advisory firms, with which the Company had significant experience. As a result of the review, Unitil Service assumed control of the work plan for the CIS implementation. Unitil Service reorganized and supplemented its CIS team with additional resources, worked with S&S to revise its quality assurance and code review process, and obtained commitments from S&S to add resources and increase quality control. The Company then engaged Grant Thornton to assist in implementation and project management. Unitil Service determined this supplemental project management and testing expertise was necessary to adequately and independently test the CIS prior to "go-live" to ensure that the CIS launch would be successful for the Unitil companies and their customers.

Q. Can you describe the testing methodology used?

A. Unitil Service's standard practice when implementing new information systems is to establish a separate hardware/software "test" environment into which the base version of the vendor's (or internally developed) software is loaded in preparation for custom configuration and testing in accordance with the Company's business process requirements.

From a project management perspective, Unitil Service tests three critical areas of the new CIS software's performance. First, it confirms that it can successfully convert all required data from the legacy system to the new system and validates and reconciles all customer, financial, regulatory and statistical attributes and information in the test environment. Second, extensive functional, transactional and system performance tests (including data uploads, detailed transactions, and daily business cycle processes) are performed to ensure the new system can perform all monthly business cycle processes according to the Unitil companies' regulatory and customer service standards. Third, the Company tests the new software/hardware's ability to close monthly operations and interface/communicate with all other necessary information systems as required.

Q. Is such a comprehensive testing methodology process necessary?

A. Yes. Comprehensive testing in a test environment to prevent errors in a production environment is far preferable to, and less expensive than, testing to detect errors after they have occurred in a production environment. This common sense approach is a foundation of the Company's system of internal controls.

Application of this quality standard of preventative testing methodology is required for approval from the Company's Senior Officers prior to "go-live" with any new system. For example, the initial CIS project plan proposed to test the first critical area listed above, the conversion process, four times before proceeding to "go-live" launch execution.

Following Unitil Service's assumption of control and reorganization of the project in 2015-2016, the Company determined that more testing of this critical area was necessary. Ultimately, the Company performed nineteen data conversions in the test environment. The twentieth data conversion occurred, successfully, during "go-live" over the July 4th weekend in 2017. Thus, for proper implementation of this project, twenty data conversions were necessary. By investing in five times the preventative testing measures (i.e, twenty versus four), Unitil Service was able to avoid the significant expense associated with executing a poor conversion and then detecting and fixing errors while in live billing production mode, which would affect the customers we serve.

Q. Were the investments in preventative testing worthwhile?

A. Yes. The cost of "cure" attributable to error detection and correction in the production environment will always far exceed the cost of prevention in the test environment. Consider further the intangible costs associated with the inconvenience to and frustration of customers, and the resulting loss of hard-earned trust by customers, regulators and state and local officials, and the true cost of an insufficiently tested CIS implementation is nearly impossible to overstate.

Q. How much testing did Unitil Service perform on the CIS prior to "go-live"?

A. Since many tests are not passed the first time, thousands of tests and re-tests were performed during the project. More than 200 Unitil and outside consulting personnel were involved in the development and testing of the CIS systems. The goal was to "go-live" in a manner which would have little to no disruption and impact on the customer experience. Testing is an iterative and exhaustive process. If a problem is discovered during a functional test, an attempt must be made to identify and rectify the problem, at which the time process is repeated until the system requirements are satisfied. If issues were discovered during the CIS testing process, Grant Thornton and Unitil Service worked with S&S to identify the issue, determine the solution, establish a timeline for the delivery of a revised system component for retesting, and test the component until it satisfied system requirements. Testing occurred in parallel for enQuesta (CIS), MDMS, and MyUnitil. This comprehensive testing process resulted in thousands of functional tests being conducted over approximately 36 months.

Q. How does the comprehensive testing and training affect the cost and schedule for a project of this magnitude and importance?

A. The importance of sufficient testing and training for a system as important as the CIS cannot be overstated. The time and expense required to comprehensively test a system of this breadth is difficult to predict at the outset because a CIS is not a "plug and play" product. A new CIS must be customized to meet a company's business functionality needs and every aspect of that customized product must be thoroughly vetted for the reasons discussed in this testimony. Accordingly, the time and expense necessary to complete testing and training are driven by factors that include the complexity of the new system and the extent to which it must interface and interact with other business platforms.

Q. How does the new CIS benefit customers?

A. The new CIS provides numerous benefits to customers. In addition to enhancing the Company's ability to provide efficient and accurately measured and billed service to customers, an important goal of the CIS was to meet evolving customer expectations. Customers expect more information to be made available from their utility and that the information be available through modern communications channels including web, mobile, e-mail, text and chat. The new CIS provides many such benefits to customers, including:

- Web interface that includes bill view and print access, recent billing and payment activity.
- Customers can sign-up for communication preferences for their bills and account management alerts. These communication preferences allow the customers to choose a message delivery option for paper, e-mail or SMS text message.
- Improvement in a customer's ability to read and understand bills, including rates, consumption and historical comparison tools for usage data.
- Customer bills include payment arrangement information and due dates.
- Customers can pay all their bills (including multiples) in a consolidated fashion. Unipay (Automatic Bank draft) is able to be utilized on active payment arrangements.
- Real-time payment interface with approval codes and account balance information.

- Automatic voiding of pending service turn-offs due to collection activity when a payment is made.
- Automatic reconnection work orders are generated for electric customers when a payment is made after being turned off.
- The CIS has more functionality to allow Customer Service Representatives ("CSRs") to assist with answering customer questions concerning the billing, account status and other communications.
- Up-to-date outage estimated times for restoration are automatically uploaded to the customer's enQuesta account, which are made available to the CSR and to the customer through the appropriate interactive voice response option.

Q. How would you characterize the implementation process for the new CIS?

A. After exhaustive testing and Quality Assurance/Quality Control assurance, the CIS was implemented over the 2017 Independence Day holiday without any material complications. The CIS implementation process was highly successful, has remained active, and has performed well since it was brought on line nearly four years ago. Today, the Company has a CIS that serves its customers well and is reflective of a modern-day service provider. Unitil Service understood from the beginning that the replacement of its legacy CIS with a completely new system would be a complicated undertaking and would require significant testing in a test environment before it would be allowed to function in the production environment. Unitil Service's thorough information systems testing methodology was the key attribute to its successful CIS implementation.

Q. What was the cost of the new CIS investment?

A. Unitil Service invested $36,832,636 in the CIS, MDMS, Customer Communications / Web Portal and System Interfaces projects.

Q. How was the new CIS investment accounted for?

A. Throughout the development process, the costs of the project were accumulated on the books of Unitil Service. In December 2017, the project was transferred from Construction Work in Process (account 107) to Plant in Service (account 101). At that time, the costs associated with the MDMS were transferred from Unitil Service to the Unitil operating companies. This balance was transferred because there were no material post "go-live" or Phase 2 items associated with the MDMS. At the end of 2018, it was determined that the CIS and other remaining systems had been operating effectively for 18 months, and in the first quarter of 2019 the balance at Unitil Service was transferred to the operating companies.

Q. Are any costs associated with the project currently being recovered in rates?

A. Yes, the costs associated with the MDMS portion of the project were included for recovery as part of the 2018 step adjustment in Docket No. DE 18-036.

Q. How much of the costs associated with the MDMS portion of the project are currently being recovered in rates?

A. The total cost of the MDMS was $7,268,134. This total project cost includes all MDMS related costs through December of 2017 when that system was completed. The total project cost was apportioned to UES in the amount of $2,398,474 using the 3-factor allocator ratio of 33%. This amount was included as part of the step increase in DE 18-036.

Q. How much is the non-MDMS portion of the project that has yet be included for recovery in UES's rates?

A. The total cost of the CIS project after removing MDMS costs is $29,564,503. Applying the three-factor allocator, the total cost of the CIS project that has yet to be included for recovery in UES's rates is $9,756,286 ($29,564,503 x 33%).

Q. How much of this cost is included in the Company's filed revenue requirement?

A. The unamortized balance at the end of the test year and included in rate base is $8,273,283.

Q. Why does the total project cost not match the amount included in the test year?

A. The difference of $1,483,003 represents the amount that has already been amortized at UES through the end of the test year prior to inclusion of the costs for recovery in rates.

Q. The CIS has been operating since July 2017. Please describe the Company's experience since that time.

A. Following the CIS implementation and related information system upgrades in July 2017:

- All bills have been processed accurately with a 100% accuracy rate and 99.8% of all bills passing the first automated checkpoint. The remaining bills are transitioned to a manual check through a daily quality assurance review.
- Nearly 90,000 customers have been enrolled in the new and improved "MyUnitil" customer portal, which is a 300% increase over the legacy site.

As Unitil Service executed its first 100 Days Transition Plan, a "bill review" team was assembled and every customer's July 2017 invoice produced by the new CIS was compared to the customer's invoice produced in the legacy CIS in June 2017 and July 2016 to ensure bill accuracy. Similarly, every customer's August and September 2017 invoice was compared to the legacy system invoice for the same months in 2016. A report was developed to compare, at the customer meter level, prior year and prior month history that occurred in the legacy CIS against current invoices produced in the new CIS. Once an invoice was deemed accurate, it was released for mailing to the customer. Over 550,000 customer invoices were issued from the new CIS in the three months following the "go-live" date, at which time Unitil Service ended this daily manual bill review effort.

A scaled down bill validation protocol remains in use today that allows the Company's billing personnel to identify and review any bills that appear to be outliers from prior historical bills.

Finally, perhaps the best indicator of the success of the new CIS is that the "go-live" occurred without notice by customers or the New Hampshire Public Utilities Commission. In fact, Unitil had not received a single complaint from a regulatory agency in any of the jurisdictions it serves about billing or other issues related to the new CIS.

Q. Have the CIS project costs been included in rates for UES's affiliate companies?

A. The portion of the CIS project costs allocated to UES's Massachusetts affiliate's gas and electric divisions were included in rates as a part of the settlement of those divisions' last base rate cases (DPU 19-130 and DPU 19-131). The CIS project costs allocated to UES's Maine natural gas affiliate, Northern Utilities, Inc. d/b/a Unitil ("Northern Utilities Maine"), are currently subject to an audit proceeding, MPUC 2021-00022. Northern Utilities Maine is participating actively in the audit proceeding to demonstrate that the full amount of the CIS project costs are reasonable and justifiable, and is pursuing full recovery in rates of these costs. Northern Utilities, Inc.'s New Hampshire division has not yet sought recovery of CIS project costs in base rates.

III. PROPOSED CHANGES TO TERMS AND CONDITIONS FOR DISTRIBUTION SERVICE

Q. Is the Company proposing changes to its Terms and Conditions for Distribution Service?

A. Yes, the proposed changes are reflected in the Company's redline tariffs included with this filing. The changes reflect updated language consistent with NHPUC rules as well a few minor changes reflecting Company current practice.

Q. Does that conclude your testimony?

A. Yes it does.

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY

OF

DANIEL J. HURSTAK

EXHIBIT DJH-1

New Hampshire Public Utilities Commission

Docket No. DE 21-030

TABLE OF CONTENTS

Attachments

Exhibit DJH-2	Pro Forma Lead-Lag Summary
Exhibit DJH-3	Supporting Workpapers

I. INTRODUCTION

Q. State your name and business address.

A. My name is Daniel J. Hurstak and my business address is 6 Liberty Lane West, Hampton, New Hampshire 03842.

Q. What is your position and what are your responsibilities?

A. I am the Chief Accounting Officer and Controller for Unitil Corporation and the Controller for Unitil Energy Systems, Inc ("UES" or the "Company"). I am also the Controller for Unitil Service Corp. ("Unitil Service"), a subsidiary of Unitil Corporation that provides managerial, financial, regulatory and engineering services to Unitil's utility subsidiaries including UES. I am responsible for the accounting and financial reporting activities for Unitil and its subsidiaries.

Q. Describe your business and educational background.

A. Prior to joining Unitil Service in March 2020, I was Vice President, Corporate Accounting, at Fidelity Investments (a multinational financial services corporation headquartered in Boston, Massachusetts), from June 2016 until February 2020. Prior to Fidelity, I was a senior manager at PricewaterhouseCoopers LLP ("PwC") (a multinational professional services network of firms operating as partnerships under the PwC brand) from September 2009 until May 2016, and I began my career at PwC in September 2001. I have a Bachelor of Science degree in Accounting from Bentley College, Waltham, Massachusetts, and I am a Certified Public Accountant in the Commonwealth of Massachusetts.

Q. Have you previously testified before the Commision or other regulatory agencies?

A. No, I have not previously testified before the New Hampshire Public Utilities Commision or other regulatory agencies.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the cash working capital requirements of UES for its delivery services. UES has identified its revenue requirements on a pro forma basis and computed the cash working capital for the test year ending December 31, 2020.

III. CASH WORKING CAPITAL

Q. Define the term "cash working capital" as used in utility ratemaking.

A. Cash working capital is the amount of investor-supplied capital required by the Company to fund operations in the time period between when expenditures are incurred to provide service to customers and when payment is actually received from customers. Cash working capital represents dollar amounts funded by investors to provide safe and reliable electric distribution services prior to receipt of payment for those services from customers. As such, cash working capital is an appropriate addition to the Company's rate base.

Q. Did you perform analyses to estimate the cash working capital of UES for the adjusted test year?

A. Yes. Exhibit DJH-2 summarizes the results of the UES lead-lag study using the pro forma revenue requirements for the test year ending December 31, 2020. As shown in these schedules, the rate base addition for the delivery cash working capital is $3,350,303, reflecting a net lag of 32.17 days.

Q. What is a lead-lag study?

A. A lead-lag study is an analysis designed to determine the funding required to operate a company on a day-to-day basis. A lead-lag study compares (1) the timing difference between the receipt of service by customers and their subsequent payment for these same services and (2) the timing difference between the incurrence of costs by the Company and its subsequent payment of these costs.

A lead-lag study therefore must compute a revenue lag or (lead), and an expense lag or (lead). Cash working capital was developed using systematic reviews of cash flows for the Company's revenues and operating expenses. The lead-lag study measures the base revenue requirement cash working capital needed for the Company's day-to-day electric operations for the 12-month pro forma period ending December 31, 2020. Exhibit DJH-2, page 1 of 3, summarizes the lead-lag study results.

Q. Define the terms "lag days" and "lead days" as used in your testimony.

A. Revenue lag is the number of days between delivery of service to the Company's customers and subsequent receipt by the Company of payment for the service. Expense lag is the number of days between the receipt of goods or services provided to the Company by vendors and payment for such goods or services by the Company. Because the Company's electric customers receive service prior to paying for it, the Company experiences a revenue lag in its daily operations. The Company typically pays expenses after vendors have provided their goods or services, which results in an expense lag. The Company will occasionally pay for goods or services before they are provided, which results in an expense lead. As shown on Exhibit DJH-2, page 1 of 3, line 31, column 5, the Company's net lag days are 32.17 days.

Q. Describe the approach you used in preparing your lead-lag study.

A. The lead-lag study starts with the identification of revenues and expenses recorded in the Company's books ("per-books") for the 12-month period ended December 31, 2020 as the basis for the analysis. First, the lag days for the recovery of revenue were calculated. Next, for operating and maintenance ("O&M") expenses, lag or lead days for each of several types of expenses, including labor, employee benefits, insurances (general, fiduciary, property), regulatory commission expenses, other O&M expenses and service company charges were calculated. In addition, lag or lead days for property taxes, other taxes, and income taxes were calculated. Once the net lag days for the test year are established on a per-books basis, they are applied to the test year pro forma revenue requirements. The lead or lag days for each of the items described in this testimony are then multiplied by the test year pro forma amounts to determine the dollar-days of cash working capital. The net dollar-days of revenue less expenses and taxes are then divided by 366 days to obtain the average daily cash working capital.

Q. Describe your calculation of revenue lag.

A. The calculation of the revenue lag is summarized on page 2 of Exhibit DJH-2. As previously described, "revenue lag" is the length of time that occurs between the Company's provision of service to its customers and the subsequent receipt of payment for those services. The existence of a revenue lag makes it necessary for investors to provide funding for the Company to pay its operating costs during the lag period.

The measurement of revenue lag consists of four components: (1) service lag, (2) billing lag, (3) collection lag, and (4) collection to receipt of available funds ("revenue float"). Since the time periods for these four components are mutually exclusive, revenue lag is computed by adding the total number of days associated with each of the four revenue lag components. This total number of lag days represents the amount of time between the recorded delivery of service to customers and the receipt of the related revenues from customers.

Q. Describe how you calculate service lag.

A. The service lag is the average time span between the mid-point of the customer's consumption interval, also known as the usage period, and the time that such usage is recorded by the Company for billing purposes. This usage period determines the average length of time over which the billed services are provided and establishes a common point in time from which to measure (1) the time of reimbursement for the billed services, and (2) the time at which the accrued costs for the usage period are actually paid. For the Company, the service lag is one-half of an average month for the year ended December 31, 2020 or 15.25 days (366/12/2). Refer to Exhibit DJH-2, page 2 for the service lag analysis.

Q. Describe the calculation of billing lag.

A. The billing lag is the time required to process and send out customer bills. The billing lag begins at the end of the service period when customer consumption is metered, and it ends when the bills are rendered and billings are posted to accounts receivable. The billing lag may be influenced by factors such as whether automated or manual meter reading systems are employed, the generation of invoices from this metering data and other processes affecting the time to post billings to accounts receivable. The Company uses an automated meter reading system that posts meter readings daily for billing the next day, and the meter reading is recorded into accounts receivable on the same day. The UES billing lag was approximately 1.01 days after considering the delay for weekends and holidays. Refer to Exhibit DJH-2, page 2 for the billing lag analysis.

Q. Describe the calculation of collection lag.

A. The collection lag identifies the time between the posting of customer bills to accounts receivable and the receipt of these billed revenues. Collection lag, which begins with the posting of bills and ends with the receipt of payment, may be influenced by payment arrangements, contract terms, postal delivery delays, customer inquiries, delinquent accounts, service termination practices, and other factors. The Company has employed the accounts receivable turnover ratio method to determine the collection lag. Using this approach, the average monthly accounts receivable balances (as measured by the average of the month-end balances for the 12 months from January 2020 to December 2020) were divided by the average daily revenues for the 12 months ended December 31, 2020. Using the accounts receivable turnover method, a collection lag of 39.02 days was computed. Refer to Exhibit DJH-2, page 2 for the collection lag analysis.

Q. Describe the final component of revenue lag, revenue float.

A. Revenue float is the time between when funds are received from customers until customer payments clear the banks and are available to the Company. Certain funds are available the day payment is received while other funds are generally available within one or two days of receipt by the bank. The following day’s bank statement reflects the prior day's bank availability of funds. Refer to Exhibit DJH-2, page 2 for the revenue float analysis.

Q. Are there other components of revenue lag for UES?

A. Yes, refer to page 2 of Exhibit DJH-2. This page includes other components such as late payment charges, disconnect / reconnect fees, and other miscellaneous revenues.

Q. What is the total revenue lag component for the lead-lag calculation?

A. The revenue lag components were combined to arrive at the total revenue lag of 56.17 days, as shown on Exhibit DJH-2, page 2.

Q. How is the lag for labor expense determined?

A. The Company's employees are paid either weekly or monthly. Using sample data, the Company measured the lag between the mid-point of the pay period and the pay date. However, not all labor costs earned by employees in the pay period are paid out as salary, the difference being payroll withholdings. In order to make an accurate calculation of total labor costs, all labor-related costs were identified, including the dates when the Company actually expended the cash for these labor costs. These labor-related costs reflect all salary components including incentive compensation, payroll taxes including withholding taxes, and a wide range of benefits. Regular payroll (weekly and monthly) costs are the largest component of labor costs and have the shortest payment lag. However, other components of labor costs have longer delays. For example, incentive compensation pay was earned from January 2020 to December 2020 and was paid in February 2021, resulting in a much longer expense lag. In addition to direct labor expense, the Company examined other labor-related costs, including payroll taxes.

Q. Describe how the lag is calculated for employee benefits.

A. The method for calculating expense lags for employee benefits uses a benefit payments approach. For each benefit payment, the service period and its mid-point were determined. The payment date was then established. The lag was then computed as the difference between the payment date and the mid-point of the service period. A weighted average of each benefit payment was then computed to determine the overall average for this category.

Q. Were other categories of O&M expense analyzed separately and included in the expense lag?

A. Yes, insurance (general, fiduciary, property) expenses, and regulatory commission expense were analyzed separately and included in the calculation of the expense lag. The lag for these expense items was also computed as the difference between the payment date and the mid-point of the service period.

Q. How was the expense lag calculated for expenses allocated from Unitil Service?

A. The expenses allocated from Unitil Service consist of Labor and Other O&M expenses that are charged to O&M accounts. The expense lag of 36.44 days assigned to these expenses was computed as the difference between the payment date for Unitil Service charges, and the mid-point of the service period, which is the mid-point of the calendar month being billed.

Q. Are Other O&M expenses included in the calculation of expense lag?

A. Yes, there are additional O&M (referred to as "Other O&M" expenses) directly paid by the Company. Because these expenses are made up of thousands of vouchers processed throughout the course of the test year, a sample was used to estimate the lags for the Company. The sample produced a lag of 54.93 days for these Other O&M direct expenses.

The sampling method used was a random sequential sample of the population using three strata. The population was sorted by dollar amounts, and the following strata were used to generate the sample:

Stratum 1: Every 3rd voucher greater than $20,000;

Stratum 2: Every 25th voucher less than $20,000 and more than $1,500;

Stratum 3: Every 150th voucher under $1,500.

The resulting sample, which accounted for 19.94% of the dollars in the population, indicated a lag of 54.93 days.

Q. Did you exclude any voucher selections from the calculation of lag days?

A. Yes. One of the selected invoices was determined to be an outlier and not representative of the Other O&M expense population. In that instance, the Company experienced a significant payment lag (in excess of 300 days) as a result of the vendor initially submitting an incorrect invoice for services which was not corrected in a timely manner. This invoice was ultimately re-submitted over eight months after the services were provided which is not typical for this vendor. The Company does a significant level of work with this vendor and other invoices from this vendor have been identified as part of the population selected to compute the Other O&M expense lag. Given the atypical nature of the payment experience, the Company excluded this invoice from the sample.

Q. Did you include any other expenses besides O&M expenses in the calculation of expense lag?

A. Yes. Since Property Taxes, Other Taxes, and Federal and State Income Taxes represent cash outlays, they were included in the calculation. All property tax payments made during 2020 were analyzed, and the expense lags computed. Other Taxes consist mostly of Payroll Taxes and Unemployment Taxes. Each type of tax was analyzed separately and assigned a lag based on the service periods and payment dates. Federal and State Income Taxes were assigned lags based on the statutory required fiscal tax year tax payments.

Q. Did the COVID-19 pandemic have an impact on the calculation of lag days for any expense category?

A. The CARES Act enacted the Employment Retention Credit ("ERC") to encourage companies to retain employees during the pandemic. The ERC is a 50% credit on employee wages for employees that are retained and cannot perform their job duties at 100% capacity as a result of pandemic restrictions. The ERC is applied as a credit to employment taxes on the Company's Form 941. In the third quarter of 2020, UES recorded an ERC of approximately $32,500 as a reduction to employment tax expense. This amount has been reflected as a pro forma adjustment to employment tax expense in this lead-lag analysis.

The Families First Coronavirus Response Act ("FFCRA") provided paid sick leave for employees who had to quarantine, care for a quarantined individual, or care for a child whose school or child care provider was closed or unavailable for reasons related to COVID-19. The FFCRA is applied as a credit to employment taxes on the Company's Form 941. In the fourth quarter of 2020, UES recorded a FFCRA of approximately $111,000 as a reduction to employment tax expense. This amount has been reflected as a pro forma adjustment to employment tax expense in this lead-lag analysis.

Q. Where have you presented the results of the cash working capital calculations for the pro forma test year?

A. The results of the lead-lag study are summarized on page 1 of Exhibit DJH-2. This page summarizes the revenue lags from page 2 and the expense lags from page 3, and presents the Company's cash working capital for the test year on a pro forma basis.

Q. Have you identified the net lag days between revenue and expense for UES for the twelve months ended December 31, 2020 on a pro forma basis?

A. Yes. As indicated by the data on page 1 of Exhibit DJH-2, the net lag for cash working capital is 32.17 days (line 31, column 5) which is slightly different than the number included in line 23, column 4 due to rounding. The positive lag indicates that cash working capital is required to compensate for the fact that the lag in the recovery of revenues is greater than the lag in the payment of expenses.

On a pro forma basis, UES's cash working capital requirement for December 31, 2020 test year is $3,350,303, or 8.79%, as shown on page 1, lines 29 and 33, of the above noted schedule. This cash working capital requirement represents the capital that must be provided and included as an addition to rate base.

IV. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

[THIS PAGE INTENTIONALLY LEFT BLANK]

Line No		Annual Expense (1)	Revenue (Lead) Lag Days (2)	Expense (Lead) Lag Days (3)	Net (Lead) Lag Days (4)	Net Day Weighted Amount (5)	Source (6)
1	**Total Revenue Lag**		56.17				Page 2 of 3 - Line 29
2							
3	**Total Expense Lag**						
4	**Operation & Maintenance Expense**						
5	Labor - Direct	$ 2,364,805	56.17	9.46	46.71	$ 110,449,243	Page 3 of 3 - Line 2
6	Labor - Incentive	$ 14,571	56.17	223.55	(167.38)	$ (2,438,899)	Page 3 of 3 - Line 3
7	Employee Benefits	$ 322,016	56.17	6.74	49.43	$ 15,916,133	Page 3 of 3 - Line 4
8	General Liability, Fiduciary & Property	$ 328,517	56.17	(138.47)	194.64	$ 63,941,083	Page 3 of 3 - Line 5
9	Regulatory Commission Expense	$ 791,884	56.17	3.09	53.08	$ 42,030,431	Page 3 of 3 - Line 6
10	Other O&M Expenses	$ 9,069,299	56.17	54.93	1.24	$ 11,232,322	Page 3 of 3 - Line 7
11	Other O&M Expenses - Service Company Charges	$ 11,392,753	56.17	36.44	19.73	$ 224,833,280	Page 3 of 3 - Line 8
12							
13	**Other Taxes**						
14	Other Taxes Excluding Property Taxes	$ 300,412	56.17	11.06	45.11	$ 13,550,981	Page 3 of 3 - Line 18
15	Property Taxes	$ 7,771,772	56.17	(26.14)	82.31	$ 639,723,409	Page 3 of 3 - Line 19
16							
17	**Income Taxes**						
18	Federal Income Taxes	$ 4,667,344	56.17	37.50	18.67	$ 87,138,994	Page 3 of 3 - Line 23
19	State Income Taxes	$ 1,091,570	56.17	37.50	18.67	$ 20,379,542	Page 3 of 3 - Line 24
20							
21							
22							
23	**Net of Revenue less Expense Lag**	$ 38,114,943	56.17	23.98	32.19	**$ 1,226,756,519**	Sum of Lines 5 to 19
24	Days					366	
25							
26	**Avg Daily Cash Working Capital Requirements**					**$ 3,350,303**	Line 33 * Line 23 Col 1
27							
28							
29	**Cash Working Capital Requirements**					**$ 3,350,303**	Line 26
30							
31	**Base Revenue Net Lag Days**					32.17	(Line 29 / Line 23, Col 1) * 366
32							
33	**Base Revenue Working Capital Percentage**					8.79%	(Line 23, Col 5 / Line 23, Col 1)/366
34							
35							
36							
37							
38							
39							
40							

Unitil Energy Systems, Inc.
Cash Working Capital Requirements
12 Months Ended December 31, 2020
Revenues Lag Summary

Line No	Revenue Lag	Revenues Billed	(Lead) Lag Days	Source	Wtg Delivery Dollar Days
1	Service Lag		15.25	See Note 1	
2					
3	Billing Lag				
4	Cycle Read Customers		1.01	Exhibit DJH-3, Pg. 1, Line 3	
5					
6	Collection Lag		39.02	Exhibit DJH-3, Pg. 1, Line 4	
7					
8	Collection to Receipt of Available Funds		1.68	Exhibit DJH-3, Pg. 1, Line 5	
9					
10	Total Sales Revenues with Increase	$ 70,048,945	56.96	Exhibit DJH-3, Pg. 1, Line 6	$ 3,990,099,349
11					
12	Late Charge Revenue	$ 275,537	44.42	See Note 2	$ 12,238,683
13					
14	Disconnect / Reconnect Charges	$ 175,310	56.96	Line 10	$ 9,985,937
15					
16	Interval Data Revenue	$ 19,686	30.50	Exhibit DJH-3, Pg. 19, Line 16	$ 600,416
17					
18	Rent from Electric Property - CATV	$ 470,144	(30.76)	Exhibit DJH-3, Pg. 20, Line 16	$ (14,460,475)
19					
20	Miscellaneous Rent	$ 428,063	30.25	Exhibit DJH-3, Pg. 21, Line 16	$ 12,948,906
21					
22	Other Electric Revenues	$ 93,780	56.96	Line 10	$ 5,341,869
23					
24	Line Extension Surcharge	$ -	56.96	Line 10	$ -
25					
26	Revenue From Trans of Electric of Others	$ 49,952	56.96	Line 10	$ 2,845,370
27					
28					
29	Total Revenue Lag	$ 71,561,417	56.17		$ 4,019,600,056
30					
31					

32 Notes:
33 1. Computed as 366/12/2
34 2. Fees are assessed on the next billing. Lag is computed as the collection lag on Line 6 plus the average of 5.4 grace period days from due date.
35
36
37
38
39
40

Unitil Energy Systems, Inc.
Cash Working Capital Requirements
12 Months Ended December 31, 2020
Cost of Service Lead Lag Summary

Line No		Revenue Req Amount	(Lead) Lag Days	Source	Weighted Amount
1	**Operation & Maintenance Expense**				
2	Labor - Direct	$ 2,364,805	9.46	Exhibit DJH-3, Pg. 22, Line 7	$ 22,381,702
3	Labor - Incentive	$ 14,571	223.55	Exhibit DJH-3, Pg. 22, Line 16	$ 3,257,355
4	Employee Benefits	$ 322,016	6.74	Exhibit DJH-3, Pg. 57, Line 20	$ 2,171,477
5	General Liability, Fiduciary & Property	$ 328,517	(138.47)	Exhibit DJH-3, Pg. 74, Line 19	$ (45,488,300)
6	Regulatory Commission Expense	$ 791,884	3.09	Exhibit DJH-3, Pg. 79, Line 6	$ 2,449,640
7	Other O&M Expenses - Direct	$ 9,069,299	54.93	Exhibit DJH-3, Pg. 80	$ 498,189,593
8	Other O&M Exp - Service Company Charges	$ 11,392,753	36.44	Exhibit DJH-3, Pg. 82, Line 7	$ 415,096,882
9	Retirement	$ 1,058,526		Non-Cash Item	
10	Distribution Bad Debt	$ 660,815		Non-Cash Item	
11	Non-Distribution Bad Debt	$ (143,623)		Non-Cash Item	
12	Arrearage Management Program (AMP) Implementation Cost	$ 459,000		Non-Cash Item	
13	Total Operating & Maintenance Expenses	$ 26,318,563			
14					
15	**Depreciation & Amortization Expense**	$ 14,241,708		Non-Cash Item	
16					
17	**Other Taxes**				
18	Other Taxes Excluding Property Taxes	$ 300,412	11.06	Exhibit DJH-3, Pg. 95, Line 9	$ 3,323,168
19	Property Taxes	$ 7,771,772	(26.14)	Exhibit DJH-3, Pg. 97, Line 14	$ (203,183,489)
20	Total Other Taxes	$ 8,072,185			
21					
22	**Income Taxes**				
23	Federal Income Taxes	$ 4,667,344	37.50	Exhibit DJH-3, Pg. 105, Line 12	$ 175,025,384
24	State Income Taxes	$ 1,091,570	37.50	Exhibit DJH-3, Pg. 106, Line 12	$ 40,933,881
25	Total Income Taxes	$ 5,758,914			
26					
27	**Provision for Deferred Income Taxes**	$ (658,148)		Non-Cash Item	
28					
29	**Interest on Customer Deposits**	$ 17,026		See Note 1	
30					
31	**Return**	$ 17,811,170			
32					
33	**Total Requirements**	$ 71,561,417			
34					
35	Notes:				
36	1. Customer Deposits is included as a deduction from Rate Base and therefore excluded from the lead lag study.				
37					
38					
39					
40					

Unitil Energy Systems, Inc.
Cash Working Capital Requirements
Revenue Lag Summary
For the Year Ended December 31, 2020

Line No.	Descripton	**Electric** Number of Days Delay
1	Revenue Lag:	
2	Receipt of Electric Service to Meter Reading	15.25 days
3	Meter Reading to Recording of Accounts Receivable	1.01 days
4	Billing to Collection	39.02 days
5	Collection to Receipt of Available Funds	1.68 days
6	Subtotal Revenue Lag Days	56.96 days

Unitil Energy Systems, Inc.
Cash Working Capital Requirements
Service Lag
For the Year Ended December 31, 2020

January 1, 2020 to December 31, 2020 Number of Days

January	31
February	29
March	31
April	30
May	31
June	30
July	31
August	31
September	30
October	31
November	30
December	31

1 - 29 Day Month	1*29	29	
4 - 30 Day Months	4*30	120	
7 - 31 Day Months	7*31	217	
	Total	366	days

366 Days / 12 Months / 2 = 15.25 days

Unitil Energy Systems, Inc.
Billing Lag
Electric Meter Reading to Recording of
Accounts Receivable

Month	Average Days
January 2020	1.02
February 2020	1.01
March 2020	1.01
April 2020	1.01
May 2020	1.01
June 2020	1.01
July 2020	1.01
August 2020	1.01
September 2020	1.02
October 2020	1.01
November 2020	1.01
December 2020	1.01
Average	1.01

Unitil Energy Systems, Inc.
Electric Meter Reading to Recording of
Accounts Receivable

Monthly Detail

January 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Weighted Days Lag
1	75,161	99.19%	1	0.99
2	259	0.34%	2	0.01
3	273	0.36%	3	0.01
4	48	0.06%	4	0.00
5	10	0.01%	5	0.00
6	6	0.01%	6	0.00
7	1	0.00%	7	0.00
8-14	13	0.02%	11	0.00
Over 14	-	0.00%	14	-
Total	75,771	100.00%		1.02

February 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Weighted Days Lag
1	75,634	99.56%	1	1.00
2	193	0.25%	2	0.01
3	61	0.08%	3	0.00
4	54	0.07%	4	0.00
5	3	0.00%	5	0.00
6	1	0.00%	6	0.00
7	6	0.01%	7	0.00
8 to 14	13	0.02%	11	0.00
Over 14	-	0.00%	14	-
Total	75,965	100.00%		1.01

March 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	75,701	99.62%	1	1.00
2	212	0.28%	2	0.01
3	37	0.05%	3	0.00
4	17	0.02%	4	0.00
5	14	0.02%	5	0.00
6	3	0.00%	6	0.00
7	2	0.00%	7	0.00
8 to 14	1	0.00%	11	0.00
Over 14	-	0.00%	14	-
Total	75,987	100.00%		1.01

April 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	75,727	99.64%	1	1.00
2	190	0.25%	2	0.01
3	51	0.07%	3	0.00
4	23	0.03%	4	0.00
5	4	0.01%	5	0.00
6	-	0.00%	6	-
7	-	0.00%	7	-
8 to 14	4	0.01%	11	0.00
Over 14	-	0.00%	14	-
Total	75,999	100.00%		1.01

May 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	75,603	99.72%	1	1.00
2	60	0.08%	2	0.00
3	42	0.06%	3	0.00
4	10	0.01%	4	0.00
5	26	0.03%	5	0.00
6	4	0.01%	6	0.00
7	1	0.00%	7	0.00
8 to 14	70	0.09%	11	0.01
Over 14	-	0.00%	14	-
Total	75,816	100.00%		1.01

June 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	75,606	99.60%	1	1.00
2	141	0.19%	2	0.00
3	61	0.08%	3	0.00
4	34	0.04%	4	0.00
5	43	0.06%	5	0.00
6	21	0.03%	6	0.00
7	1	0.00%	7	0.00
8 to 14	2	0.00%	11	0.00
Over 14	-	0.00%	14	-
Total	75,909	100.00%		1.01

July 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	75,676	99.43%	1	0.99
2	178	0.23%	2	0.00
3	34	0.04%	3	0.00
4	134	0.18%	4	0.01
5	43	0.06%	5	0.00
6	21	0.03%	6	0.00
7	6	0.01%	7	0.00
8 to 14	14	0.02%	11	0.00
Over 14	-	0.00%	14	-
Total	76,106	100.00%		1.01

August 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	75,911	99.51%	1	1.00
2	281	0.37%	2	0.01
3	46	0.06%	3	0.00
4	12	0.02%	4	0.00
5	13	0.02%	5	0.00
6	8	0.01%	6	0.00
7	4	0.01%	7	0.00
8 to 14	10	0.01%	11	0.00
Over 14	-	0.00%	14	-
Total	76,285	100.00%		1.01

September 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	76,142	99.42%	1	0.99
2	225	0.29%	2	0.01
3	26	0.03%	3	0.00
4	57	0.07%	4	0.00
5	52	0.07%	5	0.00
6	23	0.03%	6	0.00
7	24	0.03%	7	0.00
8 to 14	36	0.05%	11	0.01
Over 14	1	0.00%	14	0.00
Total	76,586	100.00%		1.02

October 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	75,724	99.18%	1	0.99
2	497	0.65%	2	0.01
3	74	0.10%	3	0.00
4	38	0.05%	4	0.00
5	15	0.02%	5	0.00
6	2	0.00%	6	0.00
7	1	0.00%	7	0.00
8 to 14	2	0.00%	11	0.00
Over 14	-	0.00%	14	-
Total	76,353	100.00%		1.01

November 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	75,959	99.60%	1	1.00
2	221	0.29%	2	0.01
3	28	0.04%	3	0.00
4	21	0.03%	4	0.00
5	16	0.02%	5	0.00
6	3	0.00%	6	0.00
7	7	0.01%	7	0.00
8 to 14	7	0.01%	11	0.00
Over 14	-	0.00%	14	-
Total	76,262	100.00%		1.01

December 2020

Days Lag	Number of Meters	Percent of Meters	Days Lag Multiplier	Wtd Days Lag
1	76,066	99.50%	1	0.99
2	275	0.36%	2	0.01
3	67	0.09%	3	0.00
4	24	0.03%	4	0.00
5	4	0.01%	5	0.00
6	5	0.01%	6	0.00
7	3	0.00%	7	0.00
8 to 14	6	0.01%	11	0.00
Over 14	-	0.00%	14	0.00
Total	76,450	100.00%		1.01

Unitil Energy Systems, Inc.
Collection Lag - Monthly Accounts Receivable Turnover
12 Months Ended December 31, 2020
Monthly Summary Electric

Line No		Days in Month	[1] Electric Sales Revenue	[2] Daily Average ([1] / Days)	[3] Accounts Receivable Electric Sales
1	January	31	$ 16,673,791	$ 537,864	$ 18,084,696
2	February	29	15,907,216	548,525	18,892,482
3	March	31	15,417,850	497,350	19,055,862
4	April	30	13,145,319	438,177	17,398,795
5	May	31	12,665,006	408,549	17,368,624
6	June	30	14,241,673	474,722	19,159,364
7	July	31	15,607,733	503,475	19,568,876
8	August	31	17,169,277	553,848	21,589,582
9	September	30	15,515,518	517,184	21,040,953
10	October	31	12,384,192	399,490	17,503,952
11	November	30	12,771,049	425,702	17,271,269
12	December	31	15,413,673	497,215	19,449,042
13					
14	Total		$ 176,912,297	$ 5,802,101	$ 226,383,498
15	Average		$ 14,742,691.38	$ 483,508.42	$ 18,865,291.49
16					
17	Payment Lag Days ([3] / [2])				39.02
18					
19					
20					

Unitil Energy Systems, Inc.
Collection to Receipt of Available Funds

Revenue Classification by Bank

Revenue is deposited into the remittance account on the day that the revenue is recorded as received.
The following day, the bank statement reflects the prior day's bank availability of funds.

Total Lag Days from Receipt of Funds to Notification of Availability of Funds 1.00 day

Availability of Funds as reported on suceeding business day.
Source: Report on Previous Day Data, Citizens Bank

	Percent of Funds				Weighted Lag Days		
2020	Available Same Day 0 Days Lag	1 Day Float 1 Day Lag	2-Day Float 2 Days Lag	Total	1 Day	2 Days	Total
January	34%	61%	5%	100%	0.61	0.09	0.71
February	39%	57%	5%	100%	0.57	0.09	0.66
March	38%	58%	4%	100%	0.58	0.08	0.66
April	36%	59%	5%	100%	0.59	0.10	0.69
May	35%	61%	4%	100%	0.61	0.09	0.69
June	33%	62%	5%	100%	0.62	0.10	0.71
July	34%	61%	5%	100%	0.61	0.09	0.70
August	37%	58%	5%	100%	0.58	0.10	0.68
September	37%	59%	4%	100%	0.59	0.08	0.67
October	35%	60%	4%	100%	0.60	0.09	0.69
November	36%	59%	5%	100%	0.59	0.10	0.69
December	37%	59%	3%	100%	0.59	0.07	0.66

Average Weighted Lag Days for Availability of Funds 0.68 days

Summary

Total Lag Days from Receipt of Funds to Notification of Availability of Funds	1.00	day
Average Weighted Lag Days for Availability of Funds	0.68	days
Total Lag Days from Collection to Availability of Funds	**1.68**	**days**

Unitil Energy Systems, Inc.
Remmitance Accounts

January, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
2	253,340	296,459	10,754	
3	72,996	170,411	13,517	
6	204,244	688,934	43,812	
7	533,373	86,435	38,854	
8	121,679	400,179	28,409	
9	7,363	172,171	18,387	
10	82,713	423,975	6,836	
13	291,390	682,527	54,224	
14	453,204	289,357	41,738	
15	182,326	242,780	8,720	
16	(6,047)	139,016	10,461	
17	70,779	114,294	4,151	
21	72,195	412,062	38,604	
22	266,554	157,817	10,197	
23	96,360	237,284	5,971	
24	90,425	95,605	5,158	
27	226,462	358,025	46,750	
28	73,181	73,635	13,165	
29	37,145	452,376	16,956	
30	86,639	210,054	19,886	
31	102,733	280,432	19,279	
	3,319,052	5,983,828	455,829	9,758,709
% of Available Funds	34%	61%	5%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.61	0.09	0.71

Unitil Energy Systems, Inc.
Remmitance Accounts

February, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
3	96,883	580,175	74,074	
4	(11,855)	66,288	61,466	
5	(8,146)	397,668	8,408	
6	485,089	599,975	16,624	
7	146,315	291,410	22,862	
10	376,356	532,348	18,499	
11	504,634	179,412	18,899	
12	188,840	249,334	44,881	
13	(22,280)	433,595	9,432	
14	246,683	127,112	6,411	
18	34,390	292,836	17,078	
19	852,315	63,977	2,977	
20	35,645	340,704	4,411	
21	76,071	48,061	10,368	
24	335,134	411,403	36,794	
25	141,326	35,459	10,286	
26	107,848	233,570	19,276	
27	23,630	150,422	42,814	
28	54,156	374,252	7,158	
	3,663,034	5,408,001	432,718	9,503,753
% of Available Funds	39%	57%	5%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.57	0.09	0.66

Unitil Energy Systems, Inc.
Remmitance Accounts

March, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
2	163,646	547,861	81,117	
3	(33,288)	99,455	49,202	
4	(659)	429,743	19,412	
5	156,415	275,586	12,332	
6	113,841	325,578	20,914	
9	249,084	883,102	23,814	
10	591,973	142,297	15,884	
11	167,234	242,430	13,350	
12	39,841	144,209	5,545	
13	105,588	156,022	3,627	
16	307,739	528,149	12,273	
17	598,236	229,231	10,032	
18	245,774	200,763	12,862	
19	9,244	87,347	10,834	
20	62,987	68,711	5,427	
23	201,195	219,905	13,844	
24	393,439	49,599	3,720	
25	117,315	199,709	5,700	
26	9,673	60,091	13,906	
27	43,356	74,025	10,831	
30	108,925	570,368	9,094	
31	3,359	42,901	9,289	
	3,654,917	5,577,082	363,009	9,595,008
% of Available Funds	38%	58%	4%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.58	0.08	0.66

Unitil Energy Systems, Inc.
Remmitance Accounts

April, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	33,772	326,384	12,229	
2	54,279	134,946	29,088	
3	43,403	167,927	22,831	
6	139,606	705,627	46,454	
7	211,775	59,867	11,991	
8	279,073	433,126	28,474	
9	25,971	180,635	14,632	
10	95,246	180,313	40,334	
13	311,882	526,964	73,936	
14	385,208	71,774	37,368	
15	95,345	389,026	17,420	
16	134,955	263,229	12,464	
17	89,590	265,676	4,633	
20	241,259	464,552	27,408	
21	(17,606)	190,893	4,994	
22	658,467	226,495	3,799	
23	13,705	149,830	7,218	
24	81,596	174,103	8,250	
27	221,117	341,084	13,866	
28	157,959	36,562	8,278	
29	172,758	224,116	13,362	
30	41,809	205,796	22,166	
	3,471,168	5,718,925	461,195	9,651,288
% of Available Funds	36%	59%	5%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.59	0.10	0.69

Unitil Energy Systems, Inc.
Remmitance Accounts

May, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	74,497	222,490	39,216	
4	62,136	644,922	36,186	
5	(26,669)	136,709	37,966	
6	228,575	368,906	38,287	
7	(14,600)	179,605	9,135	
8	105,047	170,129	9,287	
11	248,360	694,414	38,634	
12	356,645	67,189	28,180	
13	219,190	293,601	13,617	
14	4,734	135,527	5,919	
15	84,535	218,330	3,345	
18	149,202	248,906	7,038	
19	527,410	134,367	3,390	
20	186,777	405,495	7,625	
21	8,005	94,874	16,330	
22	55,631	110,401	2,992	
26	155,633	407,572	16,386	
27	263,924	22,572	8,169	
28	56,247	245,016	5,223	
29	72,889	118,729	21,601	
	2,818,166	4,919,754	348,526	8,086,446
% of Available Funds	35%	61%	4%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.61	0.09	0.69

Unitil Energy Systems, Inc.
Remmitance Accounts

June, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	83,354	614,728	53,832	
2	(44,068)	50,159	38,791	
3	20,121	324,932	15,162	
4	128,178	264,775	6,800	
5	78,723	198,818	6,802	
8	262,934	608,608	43,486	
9	384,798	74,739	30,109	
10	110,236	214,454	8,444	
11	73,613	100,485	9,357	
12	74,449	126,152	28,112	
15	189,708	589,955	21,430	
16	383,433	180,841	18,635	
17	251,539	149,907	13,002	
18	57,755	338,857	9,147	
19	48,879	91,651	7,312	
22	48,759	266,000	16,413	
23	318,082	51,797	4,054	
24	91,435	431,154	2,629	
25	43,203	72,778	4,550	
26	59,755	81,477	23,204	
29	210,634	406,687	31,706	
30	(19,228)	43,647	23,356	
	2,856,291	5,282,601	416,333	8,555,225
% of Available Funds	33%	62%	5%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.62	0.10	0.71

Unitil Energy Systems, Inc.
Remmitance Accounts

July, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	22,604	309,884	5,895	
2	28,521	199,500	8,444	
3	57,162	152,715	8,972	
6	112,634	510,198	18,501	
7	290,526	93,448	13,267	
8	210,262	311,467	14,438	
9	12,530	169,205	67,545	
10	57,906	254,111	78,957	
13	162,541	886,129	39,071	
14	421,533	190,020	11,685	
15	175,135	142,477	3,515	
16	19,047	189,438	13,946	
17	58,376	74,862	5,803	
20	208,263	356,400	20,110	
21	(7,600)	139,908	8,715	
22	722,154	182,291	10,812	
23	7,048	118,502	5,736	
24	67,761	107,775	6,003	
27	216,318	316,023	27,317	
28	138,258	103,274	12,683	
29	23,537	328,329	8,753	
30	13,151	181,011	6,914	
31	90,211	163,595	23,799	
Total	3,107,878	5,480,562	420,881	9,009,321
% of Available Funds	34%	61%	5%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.61	0.09	0.70

Unitil Energy Systems, Inc.
Remmitance Accounts

August, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
3	100,181	745,448	37,087	
4	(29,987)	54,489	15,848	
5	58,162	280,082	7,271	
6	22,561	210,858	10,902	
7	192,037	248,079	15,173	
10	339,741	723,551	79,897	
11	429,678	94,065	64,442	
12	125,167	363,502	9,109	
13	13,998	132,254	23,658	
14	83,641	173,746	10,008	
17	224,726	527,666	18,723	
18	527,618	52,247	12,632	
19	244,447	309,989	9,047	
20	57,081	194,732	18,160	
21	74,792	119,394	6,506	
24	235,823	342,981	12,266	
25	376,141	40,098	25,965	
26	210,034	262,089	25,318	
27	(4,383)	161,644	9,722	
28	65,262	151,988	9,118	
31	267,890	427,031	47,848	
Total	3,614,610	5,615,933	468,700	9,699,243
% of Available Funds	37%	58%	5%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.58	0.10	0.68

Unitil Energy Systems, Inc.
Remmitance Accounts

September, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	(36,736)	24,176	37,004	
2	46,015	358,781	8,837	
3	26,623	326,862	16,597	
4	142,727	427,959	8,327	
8	283,243	813,025	84,185	
9	721,091	133,226	67,823	
10	(4,445)	799,184	16,999	
11	86,756	195,947	13,776	
14	216,399	709,986	40,667	
15	526,874	120,247	9,215	
16	286,411	230,099	1,998	
17	17,256	76,318	4,212	
18	82,967	68,866	3,163	
21	292,201	348,543	16,321	
22	425,617	36,897	8,518	
23	108,945	126,415	13,259	
24	56,299	132,461	6,801	
25	70,730	92,355	9,573	
28	137,481	355,680	26,265	
29	(4,793)	47,982	6,516	
30	116,563	247,694	3,267	
	3,598,225	5,672,703	403,323	9,674,251
% of Available Funds	37%	59%	4%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.59	0.08	0.67

Unitil Energy Systems, Inc.
Remmitance Accounts

October, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	22,696	126,407	15,742	
2	86,063	153,413	8,534	
5	232,368	727,222	23,501	
6	126,202	33,461	47,980	
7	198,901	303,095	46,462	
8	(17,689)	483,050	19,866	
9	94,693	230,147	11,758	
13	105,752	1,205,309	13,004	
14	659,314	26,228	3,226	
15	80,650	319,890	33,622	
16	78,758	170,029	23,806	
19	197,878	372,543	58,991	
20	609,865	135,742	33,183	
21	109,884	235,703	9,625	
22	49,248	125,626	5,886	
23	75,731	177,802	7,749	
26	148,692	337,950	21,066	
27	407,060	36,330	5,125	
28	22,394	364,907	25,638	
29	69,665	225,623	6,147	
30	97,587	130,551	19,252	
	3,455,711	5,921,028	440,163	9,816,902
% of Available Funds	35%	60%	4%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.60	0.09	0.69

Unitil Energy Systems, Inc.
Remmitance Accounts

November, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
2	74,895	534,179	47,083	
3	10,959	158,028	26,455	
4	203,588	193,701	6,379	
5	24,494	260,123	22,400	
6	74,887	295,117	11,220	
9	407,384	681,241	22,085	
10	503,979	102,221	51,719	
12	134,524	259,448	55,009	
13	29,921	116,285	10,594	
16	165,063	715,599	13,357	
17	506,056	267,682	6,122	
18	133,334	285,947	9,708	
19	8,391	97,318	5,974	
20	95,258	117,121	9,393	
23	133,229	223,977	29,308	
24	258,770	18,018	21,655	
25	37,465	108,454	6,673	
27	165,701	216,286	41,338	
30	(339)	172,403	20,773	
	2,967,560	4,823,148	417,245	8,207,953
% of Available Funds	36%	59%	5%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.59	0.10	0.69

Unitil Energy Systems, Inc.
Remmitance Accounts

December, 2020	Available Balance	1 Day Float	2 Day Float	Total Available + Float
1	92,147	166,309	18,715	
2	45,461	207,174	4,339	
3	23,133	222,847	8,529	
4	77,905	363,613	7,004	
7	469,364	615,172	53,545	
8	261,399	77,879	43,492	
9	90,049	349,572	8,727	
10	13,440	120,491	4,431	
11	72,178	233,939	8,746	
14	274,914	419,500	12,099	
15	522,780	147,362	11,077	
16	169,636	90,751	2,489	
17	10,575	89,372	12,100	
18	50,007	66,446	11,506	
21	146,115	272,950	19,864	
22	240,207	94,609	4,403	
23	25,709	127,237	4,417	
24	63,942	165,758	6,842	
28	72,178	233,939	8,746	
29	169,313	7,864	2,782	
30	87,629	524,031	7,325	
31	88,581	260,237	8,592	
	3,066,664	4,857,052	269,770	8,193,486
% of Available Funds	37%	59%	3%	100%
Float Days	0	1	2	
Weighted Float Days	-	0.59	0.07	0.66

Unitil Energy Systems, Inc.
Interval Data
12 Months Ended Dec 31, 2020

G/L #10-20-08-99-451-02-00

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	January	$ 6,429	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/16/20 12:00 AM	30.50	$ 196,088
4	February	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	-
5	March	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	-
6	April	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	-
7	May	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	-
8	June	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	-
9	July	6,088	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/16/20 12:00 AM	30.50	185,684
10	August	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	-
11	September	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	-
12	October	7,169	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/16/20 12:00 AM	30.50	218,645
13	November	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	-
14	December	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	-
15									
16		$ 19,686						30.50	$ 600,416
17									
18									
19									
20									
21									
22									
23									
24									
25									

Unitil Energy Systems, Inc.
CATV Rent
12 Months Ended Dec 31, 2020

G/L #10-20-08-00-454-00-00

Line			Service Period		Total	Midpoint	Payment	(Lead) Lag	Weighted
No	Payroll Description	Amount	Start	End	Days	Service Period	Date	Days	Dollar Days
1	**Weekly**								
2									
3	January	$ 113,983	2/1/20 12:00 AM	5/1/20 12:00 AM	90	3/17/20 12:00 AM	2/16/20 12:00 AM	(30.00)	$ (3,419,477)
4	February	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	-
5	March	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	-
6	April	116,916	5/1/20 12:00 AM	8/1/20 12:00 AM	92	6/16/20 12:00 AM	5/16/20 12:00 AM	(31.00)	(3,624,387)
7	May	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	-
8	June	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	-
9	July	119,156	8/1/20 12:00 AM	11/1/20 12:00 AM	92	9/16/20 12:00 AM	8/16/20 12:00 AM	(31.00)	(3,693,840)
10	August	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	-
11	September	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	-
12	October	120,089	11/1/20 12:00 AM	2/1/21 12:00 AM	92	12/17/20 12:00 AM	11/16/20 12:00 AM	(31.00)	(3,722,771)
13	November	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	-
14	December	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	1/0/00 12:00 AM	1/0/00 12:00 AM	-	-
15									
16		$ 470,144						(30.76)	$ (14,460,475)
17									
18									
19									
20									
21									
22									
23									
24									
25									

Unitil Energy Systems, Inc.
Miscellaneous Rent
12 Months Ended Dec 31, 2020

G/L #10-20-10-00-454-02-00

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	January	$ 9,588	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/16/20 12:00 AM	30.50	$ 292,434
4	February	9,588	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/16/20 12:00 AM	29.50	282,846
5	March	9,588	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/16/20 12:00 AM	30.50	292,434
6	April	9,588	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/16/20 12:00 AM	30.00	287,640
7	May	9,588	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/16/20 12:00 AM	30.50	292,434
8	June	9,588	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/16/20 12:00 AM	30.00	287,640
9	July	9,588	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/16/20 12:00 AM	30.50	292,434
10	August	9,588	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/16/20 12:00 AM	30.50	292,434
11	September	9,588	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/16/20 12:00 AM	30.00	287,640
12	October	9,588	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/16/20 12:00 AM	30.50	292,434
13	November	9,588	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/16/20 12:00 AM	30.00	287,640
14	December	9,588	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	1/16/21 12:00 AM	30.50	292,434
15									
16		$ 115,056			366			30.25	$ 3,480,444
17									
18									
19									
20									
21									
22									
23									
24									
25									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Summary Total Payroll Lead Lag Summary - ADP and Non ADP

Line No	Gross Payroll Items	Amount	(Lead) Lag Days	Weighted Dollar Days
1				
2	**Regular Payroll**			
3	Total ADP Weekly & Monthly	$ 1,268,493	6.33	$ 8,025,123
4				
5	Total Non ADP Weekly & Monthly	241,683	25.93	6,267,946
6				
7	Total Weekly & Monthly Payroll	$1,510,177	9.46	$ 14,293,068.23
8				
9				
10				
11	**Incentive Payroll**			
12	Total ADP Weekly & Monthly	$ 138,642	223.50	$ 30,986,550
13				
14	Total Non ADP Weekly & Monthly	3,526	225.50	795,088
15				
16	Total Weekly & Monthly Payroll	$ 142,168.17	223.55	$ 31,781,637.78
17				
18				
19				
20				
21				
22				
23				
24				
25				

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Non ADP Payroll Deductions Lead Lag Summary

Line No	Gross Payroll Items	Amount	(Lead) Lag Days	Weighted Dollar Days
1				
2	**Weekly**			
3	401K Loan	$ 21,024	7.42	$ 155,925
4	401K Taxable & Deferred	76,221	7.42	565,518
5	Health Insurance Premium	39,864	51.30	2,045,027
6	Health Savings Account	8,289	7.45	61,740
7	Dental Premium	2,175	51.30	111,574
8	Vision Premium	533	30.00	16,005
9	Vision Additional	-	-	-
10	Supplemental Life Premium	2,013	7.42	14,932
11	Supplemental AD&D Premium	7	7.42	50
12	Stock Purchase	6,660	7.42	49,395
13	Charity 3	303	7.42	2,247
14	Miscellaneous	285	7.50	2,137
15	Workers Compensation Adjustment	-	-	-
16	PC Purchase Loan	420	(334.58)	(140,525)
17	Service Award	-	-	-
18	Union Dues	11,921	7.42	88,415
19	FSA Medical	672	7.46	5,006
20	Taxed Life Insurance	4,001	7.42	29,673
21	Auto Adjustment	-	-	-
22	Education Aid	-	-	-
23				
24	Total Weekly Payroll	$ 174,388	17.24	$ 3,007,118
25				
26				
27	**Monthly**			
28	401K Loan	$ 11,129	7.69	$ 85,600
29	401K Taxable & Deferred	25,839	7.66	198,043
30	Health Insurance Premium	7,735	51.30	396,808
31	Health Savings Account	5,475	7.67	41,975
32	Dental Premium	612	51.30	31,374
33	Vision Premium	149	30.00	4,464
34	Vision Additional	-	-	-
35	Supplemental Life Premium	388	7.67	2,971
36	Supplemental AD&D Premium	45	7.67	345
37	Stock Purchase	2,520	7.67	19,320
38	Charity 3	228	7.67	1,748
39	Miscellaneous	100	9.00	900
40	Workers Compensation Adjustment	-	-	-
41	PC Purchase Loan	-	-	-
42	Service Award	-	-	-
43	Union Dues	-	-	-
44	FSA Medical	-	-	-
45	Taxed Life Insurance	1,714	7.67	13,142
46	Auto Adjustment	11,362	216.88	2,464,137
47	Education Aid	-	-	-
48				
49	Total Monthly Payroll	$ 67,295	48.46	$ 3,260,827
50				
51				
52	Total Weekly & Monthly	$ 241,683	25.93	$ 6,267,946
53				
54				
55	**Incentive Pay**			
56	401K Taxable & Deferred	$ 3,526	225.50	$ 795,088
57				
58	Total Incentive Payroll	$ 3,526	225.50	$ 795,088
59				
60				
61				
62				
63				
64				
65				

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Total Payroll Service

Line No	Payroll Description	Grand Total Payroll Amount	Total ADP Payroll Deductions	Total Non ADP Payroll Deductions	Difference
1	**Weekly**				
2					
3	9/26/2020	$ 94,184	$ 79,356	$ 14,828	$ -
4	10/3/2020	89,557	75,339	14,218	-
5	10/10/2020	120,605	104,704	15,901	-
6	10/17/2020	94,379	80,314	14,065	-
7	10/24/2020	87,219	73,313	13,906	-
8	10/31/2020	93,518	78,822	14,696	-
9	11/7/2020	102,250	87,706	14,544	-
10	11/14/2020	97,805	83,527	14,278	-
11	11/21/2020	100,707	86,673	14,034	-
12	11/28/2020	101,388	87,761	13,627	-
13	12/5/2020	116,495	101,972	14,523	-
14	12/12/2020	147,796	132,027	15,769	-
15					
16					
17		$ 1,245,903	$ 1,071,515	$ 174,388	
18					
19					
20	**Monthly**				
21					
22	10/31/2020	$ 117,443	$ 99,075	$ 18,367	-
23	11/30/2020	123,796	97,476	26,320	-
24	12/31/2020	120,808	98,199	22,609	-
25					
26		$ 362,046	$ 294,751	$ 67,295	
27					
28					
29	**Incentive Pay**				
30					
31	Incentive Pay Feb	$ 153,155	$ 149,629	$ 3,526	-
32					
33		$ 153,155	$ 149,629	$ 3,526	
34					
35					
36	Total	$ 1,761,104	$ 1,515,895	$ 245,209	
37					
38					
39					
40					

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
401K Loan

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ 1,752	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	10/1/20 12:00 AM	7.50	$ 13,140
4	10/3/2020	1,752	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/8/20 12:00 AM	7.50	13,140
5	10/10/2020	1,752	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/15/20 12:00 AM	7.50	13,140
6	10/17/2020	1,752	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/22/20 12:00 AM	7.50	13,140
7	10/24/2020	1,752	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/29/20 12:00 AM	7.50	13,140
8	10/31/2020	1,752	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/5/20 12:00 AM	7.50	13,140
9	11/7/2020	1,752	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	7.50	13,140
10	11/14/2020	1,752	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/19/20 12:00 AM	7.50	13,140
11	11/21/2020	1,752	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/25/20 12:00 AM	6.50	11,388
12	11/28/2020	1,752	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/3/20 12:00 AM	7.50	13,140
13	12/5/2020	1,752	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/10/20 12:00 AM	7.50	13,140
14	12/12/2020	1,752	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/17/20 12:00 AM	7.50	13,140
15									
16		$ 21,024						7.42	$ 155,925
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ 3,551	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/23/20 12:00 AM	6.50	$ 23,084
22	11/30/2020	3,789	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/25/20 12:00 AM	9.00	34,100
23	12/31/2020	3,789	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/24/20 12:00 AM	7.50	28,416
24									
25		$ 11,129						7.69	$ 85,600
26									
27									
28									
29	Payment date indicates the check date								
30									
31									
32									
33									
34									
35									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
401K Taxable & Deferred

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ 6,112	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	10/1/20 12:00 AM	7.50	$ 45,838
4	10/3/2020	5,902	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/8/20 12:00 AM	7.50	44,262
5	10/10/2020	7,322	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/15/20 12:00 AM	7.50	54,912
6	10/17/2020	5,822	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/22/20 12:00 AM	7.50	43,663
7	10/24/2020	5,662	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/29/20 12:00 AM	7.50	42,467
8	10/31/2020	6,453	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/5/20 12:00 AM	7.50	48,397
9	11/7/2020	6,464	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	7.50	48,482
10	11/14/2020	6,287	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/19/20 12:00 AM	7.50	47,152
11	11/21/2020	6,143	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/25/20 12:00 AM	6.50	39,928
12	11/28/2020	5,826	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/3/20 12:00 AM	7.50	43,698
13	12/5/2020	6,356	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/10/20 12:00 AM	7.50	47,669
14	12/12/2020	7,873	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/17/20 12:00 AM	7.50	59,048
15									
16		$ 76,221						7.42	$ 565,518
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ 8,641	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/23/20 12:00 AM	6.50	$ 56,167
22	11/30/2020	8,593	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/25/20 12:00 AM	9.00	77,338
23	12/31/2020	8,605	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/24/20 12:00 AM	7.50	64,538
24									
25		$ 25,839						7.66	$ 198,043
26									
27									
28	**Incentive Pay**								
29									
30	Incentive Pay Feb	$ 3,526	1/1/19 12:00 AM	1/1/20 12:00 AM	365	7/2/19 12:00 PM	2/13/20 12:00 AM	225.50	$ 795,088
31									
32		$ 3,526						225.50	$ 795,088
33									
34	Annualized Lag	$ 411,769						9.35	$ 3,849,332
35									
36									
37									
38	Payment date indicates the check date								
39									
40									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Health Insurance Premium

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ 3,369	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	10/1/20 12:00 AM	51.30	$ 172,821
4	10/3/2020	3,369	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/8/20 12:00 AM	51.30	172,821
5	10/10/2020	3,030	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/15/20 12:00 AM	51.30	155,418
6	10/17/2020	3,344	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/22/20 12:00 AM	51.30	171,552
7	10/24/2020	3,344	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/29/20 12:00 AM	51.30	171,552
8	10/31/2020	3,344	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/5/20 12:00 AM	51.30	171,552
9	11/7/2020	3,344	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	51.30	171,552
10	11/14/2020	3,344	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/19/20 12:00 AM	51.30	171,552
11	11/21/2020	3,344	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/25/20 12:00 AM	51.30	171,552
12	11/28/2020	3,258	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/3/20 12:00 AM	51.30	167,149
13	12/5/2020	3,430	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/10/20 12:00 AM	51.30	175,955
14	12/12/2020	3,344	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/17/20 12:00 AM	51.30	171,552
15									
16		$ 39,864						51.30	$ 2,045,027
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ 2,473	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/23/20 12:00 AM	51.30	$ 126,849
22	11/30/2020	2,631	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/25/20 12:00 AM	51.30	134,980
23	12/31/2020	2,631	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/24/20 12:00 AM	51.30	134,980
24									
25		$ 7,735						51.30	$ 396,808
26									
27									
28									
29	The employee contribution toward health insurance is an offset to the expense.								
30	Lag days are based on medical and prescription claims.								
31	UES is self insured.								
32									
33									
34									
35									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Health Savings Account

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ 1,173	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	10/1/20 12:00 AM	7.50	$ 8,798
4	10/3/2020	773	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/8/20 12:00 AM	7.50	5,798
5	10/10/2020	1,403	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/15/20 12:00 AM	7.50	10,523
6	10/17/2020	728	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/22/20 12:00 AM	7.50	5,460
7	10/24/2020	728	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/29/20 12:00 AM	7.50	5,460
8	10/31/2020	728	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/5/20 12:00 AM	7.50	5,460
9	11/7/2020	616	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	7.50	4,620
10	11/14/2020	428	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/19/20 12:00 AM	7.50	3,210
11	11/21/2020	428	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/25/20 12:00 AM	6.50	2,782
12	11/28/2020	428	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/3/20 12:00 AM	7.50	3,210
13	12/5/2020	428	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/10/20 12:00 AM	7.50	3,210
14	12/12/2020	428	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/17/20 12:00 AM	7.50	3,210
15									
16		$ 8,289						7.45	$ 61,740
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ 1,825	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/23/20 12:00 AM	6.50	$ 11,863
22	11/30/2020	1,825	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/25/20 12:00 AM	9.00	16,425
23	12/31/2020	1,825	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/24/20 12:00 AM	7.50	13,688
24									
25		$ 5,475						7.67	$ 41,975
26									
27									
28									
29	Payment date indicates the check date								
30									
31									
32									
33									
34									
35									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Dental Premium

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ 185	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	10/1/20 12:00 AM	51.30	$ 9,475
4	10/3/2020	185	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/8/20 12:00 AM	51.30	9,475
5	10/10/2020	163	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/15/20 12:00 AM	51.30	8,374
6	10/17/2020	182	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/22/20 12:00 AM	51.30	9,361
7	10/24/2020	182	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/29/20 12:00 AM	51.30	9,361
8	10/31/2020	182	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/5/20 12:00 AM	51.30	9,361
9	11/7/2020	182	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	51.30	9,361
10	11/14/2020	182	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/19/20 12:00 AM	51.30	9,361
11	11/21/2020	182	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/25/20 12:00 AM	51.30	9,361
12	11/28/2020	179	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/3/20 12:00 AM	51.30	9,170
13	12/5/2020	186	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/10/20 12:00 AM	51.30	9,553
14	12/12/2020	182	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/17/20 12:00 AM	51.30	9,361
15									
16		$ 2,175						51.30	$ 111,574
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ 198	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/23/20 12:00 AM	51.30	$ 10,139
22	11/30/2020	207	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/25/20 12:00 AM	51.30	10,617
23	12/31/2020	207	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/24/20 12:00 AM	51.30	10,617
24									
25		$ 612						51.30	$ 31,374
26									
27									
28									
29	The employee contribution toward dental insurance is an offset to the expense.								
30	Lag days are based on health insurance premium.								
31	UES is self insured.								
32									
33									
34									
35									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Vision Premium

Line			Service Period		Total	Midpoint	Payment	(Lead) Lag	Weighted
No	Payroll Description	Amount	Start	End	Days	Service Period	Date	Days	Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ 46	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	10/1/20 12:00 AM	30.00	$ 1,375
4	10/3/2020	46	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/8/20 12:00 AM	30.00	1,375
5	10/10/2020	39	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/15/20 12:00 AM	30.00	1,178
6	10/17/2020	45	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/22/20 12:00 AM	30.00	1,342
7	10/24/2020	45	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/29/20 12:00 AM	30.00	1,342
8	10/31/2020	45	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/5/20 12:00 AM	30.00	1,342
9	11/7/2020	45	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	30.00	1,342
10	11/14/2020	45	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/19/20 12:00 AM	30.00	1,342
11	11/21/2020	45	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/25/20 12:00 AM	30.00	1,342
12	11/28/2020	44	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/3/20 12:00 AM	30.00	1,309
13	12/5/2020	46	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/10/20 12:00 AM	30.00	1,375
14	12/12/2020	45	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/17/20 12:00 AM	30.00	1,342
15									
16		$ 533						30.00	$ 16,005
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ 48	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/23/20 12:00 AM	30.00	$ 1,440
22	11/30/2020	50	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/25/20 12:00 AM	30.00	1,512
23	12/31/2020	50	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/24/20 12:00 AM	30.00	1,512
24									
25		$ 149						30.00	$ 4,464
26									
27									
28									
29	UES is self insured for Vision.								
30	The employee contribution toward vision insurance is an offset to the expense.								
31	The lag until payment is made to the provider is estimated to be 30 days after the payroll deduction.								
32									
33									
34									
35									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Vision Additional

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ -	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	10/1/20 12:00 AM	30.00	$ -
4	10/3/2020	-	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/8/20 12:00 AM	30.00	-
5	10/10/2020	-	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/15/20 12:00 AM	30.00	-
6	10/17/2020	-	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/22/20 12:00 AM	30.00	-
7	10/24/2020	-	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/29/20 12:00 AM	30.00	-
8	10/31/2020	-	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/5/20 12:00 AM	30.00	-
9	11/7/2020	-	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	30.00	-
10	11/14/2020	-	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/19/20 12:00 AM	30.00	-
11	11/21/2020	-	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/25/20 12:00 AM	30.00	-
12	11/28/2020	-	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/3/20 12:00 AM	30.00	-
13	12/5/2020	-	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/10/20 12:00 AM	30.00	-
14	12/12/2020	-	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/17/20 12:00 AM	30.00	-
15									
16		$ -						-	$ -
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ -	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/23/20 12:00 AM	30.00	$ -
22	11/30/2020	-	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/25/20 12:00 AM	30.00	-
23	12/31/2020	-	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/24/20 12:00 AM	30.00	-
24									
25		$ -						-	$ -
26									
27									
28									
29									
30									
31									
32									
33									
34									
35									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Supplemental Life Premium

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ 168	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	10/1/20 12:00 AM	7.50	$ 1,258
4	10/3/2020	168	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/8/20 12:00 AM	7.50	1,258
5	10/10/2020	168	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/15/20 12:00 AM	7.50	1,258
6	10/17/2020	168	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/22/20 12:00 AM	7.50	1,258
7	10/24/2020	168	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/29/20 12:00 AM	7.50	1,258
8	10/31/2020	168	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/5/20 12:00 AM	7.50	1,258
9	11/7/2020	168	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	7.50	1,258
10	11/14/2020	168	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/19/20 12:00 AM	7.50	1,258
11	11/21/2020	168	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/25/20 12:00 AM	6.50	1,091
12	11/28/2020	168	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/3/20 12:00 AM	7.50	1,258
13	12/5/2020	168	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/10/20 12:00 AM	7.50	1,258
14	12/12/2020	168	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/17/20 12:00 AM	7.50	1,258
15									
16		$ 2,013						7.42	$ 14,932
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ 129	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/23/20 12:00 AM	6.50	$ 840
22	11/30/2020	129	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/25/20 12:00 AM	9.00	1,163
23	12/31/2020	129	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/24/20 12:00 AM	7.50	969
24									
25		$ 388						7.67	$ 2,971
26									
27									
28									
29	Total Weighted Lag	$ 2,401						7.46	$ 17,903
30									
31									
32									
33	Payment date indicates the check date								
34									
35									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Supplemental AD&D Premium

Line No	Payroll Description	Net Payroll Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ 1	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	10/1/20 12:00 AM	7.50	$ 4
4	10/3/2020	1	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/8/20 12:00 AM	7.50	4
5	10/10/2020	1	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/15/20 12:00 AM	7.50	4
6	10/17/2020	1	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/22/20 12:00 AM	7.50	4
7	10/24/2020	1	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/29/20 12:00 AM	7.50	4
8	10/31/2020	1	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/5/20 12:00 AM	7.50	4
9	11/7/2020	1	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	7.50	4
10	11/14/2020	1	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/19/20 12:00 AM	7.50	4
11	11/21/2020	1	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/25/20 12:00 AM	6.50	4
12	11/28/2020	1	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/3/20 12:00 AM	7.50	4
13	12/5/2020	1	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/10/20 12:00 AM	7.50	4
14	12/12/2020	1	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/17/20 12:00 AM	7.50	4
15									
16		$ 7						7.42	$ 50
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ 15	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/23/20 12:00 AM	6.50	$ 98
22	11/30/2020	15	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/25/20 12:00 AM	9.00	135
23	12/31/2020	15	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/24/20 12:00 AM	7.50	113
24									
25		$ 45						7.67	$ 345
26									
27									
28									
29	Total Weighted Lag	$ 52						7.63	$ 395
30									
31									
32									
33	Payment date reflects the check date								
34									
35									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Stock Purchase

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ 555	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	10/1/20 12:00 AM	7.50	$ 4,163
4	10/3/2020	555	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/8/20 12:00 AM	7.50	4,163
5	10/10/2020	555	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/15/20 12:00 AM	7.50	4,163
6	10/17/2020	555	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/22/20 12:00 AM	7.50	4,163
7	10/24/2020	555	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/29/20 12:00 AM	7.50	4,163
8	10/31/2020	555	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/5/20 12:00 AM	7.50	4,163
9	11/7/2020	555	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	7.50	4,163
10	11/14/2020	555	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/19/20 12:00 AM	7.50	4,163
11	11/21/2020	555	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/25/20 12:00 AM	6.50	3,608
12	11/28/2020	555	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/3/20 12:00 AM	7.50	4,163
13	12/5/2020	555	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/10/20 12:00 AM	7.50	4,163
14	12/12/2020	555	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/17/20 12:00 AM	7.50	4,163
15									
16		$ 6,660						7.42	$ 49,395
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ 840	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/23/20 12:00 AM	6.50	$ 5,460
22	11/30/2020	840	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/25/20 12:00 AM	9.00	7,560
23	12/31/2020	840	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/24/20 12:00 AM	7.50	6,300
24									
25		$ 2,520						7.67	$ 19,320
26									
27									
28									
29	Payment date indicates the check date								
30									
31									
32									
33									
34									
35									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Charity 3

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ 25	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	10/1/20 12:00 AM	7.50	$ 189
4	10/3/2020	25	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/8/20 12:00 AM	7.50	189
5	10/10/2020	25	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/15/20 12:00 AM	7.50	189
6	10/17/2020	25	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/22/20 12:00 AM	7.50	189
7	10/24/2020	25	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/29/20 12:00 AM	7.50	189
8	10/31/2020	25	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/5/20 12:00 AM	7.50	189
9	11/7/2020	25	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	7.50	189
10	11/14/2020	25	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/19/20 12:00 AM	7.50	189
11	11/21/2020	25	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/25/20 12:00 AM	6.50	164
12	11/28/2020	25	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/3/20 12:00 AM	7.50	189
13	12/5/2020	25	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/10/20 12:00 AM	7.50	189
14	12/12/2020	25	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/17/20 12:00 AM	7.50	189
15									
16		$ 303						7.42	$ 2,247
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ 76	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/23/20 12:00 AM	6.50	$ 494
22	11/30/2020	76	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/25/20 12:00 AM	9.00	684
23	12/31/2020	76	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/24/20 12:00 AM	7.50	570
24									
25		$ 228						7.67	$ 1,748
26									
27									
28									
29	Payment date indicates the check date								
30	United Way.								
31									
32									
33									
34									
35									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Miscellaneous

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Payment Date	(Lead) Lag Days	Weighted Dollar Days	
1	**Weekly**									
2										
3	9/26/2020	$ -	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	10/1/20 12:00 AM	7.50	$ -	
4	10/3/2020	-	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/8/20 12:00 AM	7.50	-	
5	10/10/2020	-	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/15/20 12:00 AM	7.50	-	
6	10/17/2020	-	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/22/20 12:00 AM	7.50	-	
7	10/24/2020	-	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/29/20 12:00 AM	7.50	-	
8	10/31/2020	-	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/5/20 12:00 AM	7.50	-	
9	11/7/2020	-	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	7.50	-	
10	11/14/2020	100	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/19/20 12:00 AM	7.50	750	Activity prize
11	11/21/2020	-	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/25/20 12:00 AM	6.50	-	
12	11/28/2020	-	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/3/20 12:00 AM	7.50	-	
13	12/5/2020	185	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/10/20 12:00 AM	7.50	1,387	Activity prize
14	12/12/2020	-	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/17/20 12:00 AM	7.50	-	
15										
16		$ 285						7.50	$ 2,137	
17										
18										
19	**Monthly**									
20										
21	10/31/2020	$ -	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/23/20 12:00 AM	6.50	$ -	
22	11/30/2020	100	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/25/20 12:00 AM	9.00	900	Activity prize
23	12/31/2020	-	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/24/20 12:00 AM	7.50	-	
24										
25		$ 100						9.00	$ 900	
26										
27										
28										
29										
30										
31										
32										
33										
34										
35										

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Workers Compensation Adjustment

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ -	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	10/1/20 12:00 AM	7.50	$ -
4	10/3/2020	-	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/8/20 12:00 AM	7.50	-
5	10/10/2020	-	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/15/20 12:00 AM	7.50	-
6	10/17/2020	-	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/22/20 12:00 AM	7.50	-
7	10/24/2020	-	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/29/20 12:00 AM	7.50	-
8	10/31/2020	-	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/5/20 12:00 AM	7.50	-
9	11/7/2020	-	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	7.50	-
10	11/14/2020	-	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/19/20 12:00 AM	7.50	-
11	11/21/2020	-	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/25/20 12:00 AM	6.50	-
12	11/28/2020	-	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/3/20 12:00 AM	7.50	-
13	12/5/2020	-	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/10/20 12:00 AM	7.50	-
14	12/12/2020	-	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/17/20 12:00 AM	7.50	-
15									
16		$ -						-	$ -
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ -	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/23/20 12:00 AM	6.50	$ -
22	11/30/2020	-	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/25/20 12:00 AM	9.00	-
23	12/31/2020	-	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/24/20 12:00 AM	7.50	-
24									
25		$ -						-	$ -
26									
27									
28									
29									
30									
31									
32									
33									
34									
35									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
PC Purchase Loan

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ 35	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	10/1/20 12:00 AM	(334.58)	$ (11,710)
4	10/3/2020	35	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/8/20 12:00 AM	(334.58)	(11,710)
5	10/10/2020	35	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/15/20 12:00 AM	(334.58)	(11,710)
6	10/17/2020	35	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/22/20 12:00 AM	(334.58)	(11,710)
7	10/24/2020	35	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/29/20 12:00 AM	(334.58)	(11,710)
8	10/31/2020	35	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/5/20 12:00 AM	(334.58)	(11,710)
9	11/7/2020	35	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	(334.58)	(11,710)
10	11/14/2020	35	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/19/20 12:00 AM	(334.58)	(11,710)
11	11/21/2020	35	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/25/20 12:00 AM	(334.58)	(11,710)
12	11/28/2020	35	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/3/20 12:00 AM	(334.58)	(11,710)
13	12/5/2020	35	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/10/20 12:00 AM	(334.58)	(11,710)
14	12/12/2020	35	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/17/20 12:00 AM	(334.58)	(11,710)
15									
16		$ 420						(334.58)	$ (140,525)
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ -	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/23/20 12:00 AM	(334.58)	$ -
22	11/30/2020	-	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/25/20 12:00 AM	(334.58)	-
23	12/31/2020	-	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/24/20 12:00 AM	(334.58)	-
24									
25		$ -						-	$ -
26									
27									
28									
29	Average Length of Loan is 22 months.								
30									
31									
32									
33									
34									
35									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Service Award

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ -	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	10/1/20 12:00 AM	7.50	$ -
4	10/3/2020	-	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/8/20 12:00 AM	7.50	-
5	10/10/2020	-	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/15/20 12:00 AM	7.50	-
6	10/17/2020	-	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/22/20 12:00 AM	7.50	-
7	10/24/2020	-	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/29/20 12:00 AM	7.50	-
8	10/31/2020	-	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/5/20 12:00 AM	7.50	-
9	11/7/2020	-	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	7.50	-
10	11/14/2020	-	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/19/20 12:00 AM	7.50	-
11	11/21/2020	-	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/25/20 12:00 AM	6.50	-
12	11/28/2020	-	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/3/20 12:00 AM	7.50	-
13	12/5/2020	-	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/10/20 12:00 AM	7.50	-
14	12/12/2020	-	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/17/20 12:00 AM	7.50	-
15									
16		$ -						-	$ -
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ -	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/23/20 12:00 AM	6.50	$ -
22	11/30/2020	-	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/25/20 12:00 AM	9.00	-
23	12/31/2020	-	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/24/20 12:00 AM	7.50	-
24									
25		$ -						-	$ -
26									
27									
28									
29	Service Awards are for every 5 years of Service.								
30									
31									
32									
33									
34									
35									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Union Dues

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ 993	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	10/1/20 12:00 AM	7.50	$ 7,448
4	10/3/2020	993	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/8/20 12:00 AM	7.50	7,448
5	10/10/2020	993	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/15/20 12:00 AM	7.50	7,448
6	10/17/2020	993	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/22/20 12:00 AM	7.50	7,448
7	10/24/2020	993	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/29/20 12:00 AM	7.50	7,448
8	10/31/2020	993	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/5/20 12:00 AM	7.50	7,448
9	11/7/2020	993	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	7.50	7,448
10	11/14/2020	993	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/19/20 12:00 AM	7.50	7,448
11	11/21/2020	993	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/25/20 12:00 AM	6.50	6,455
12	11/28/2020	993	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/3/20 12:00 AM	7.50	7,448
13	12/5/2020	993	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/10/20 12:00 AM	7.50	7,448
14	12/12/2020	997	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/17/20 12:00 AM	7.50	7,476
15									
16		$ 11,921						7.42	$ 88,415
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ -	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/23/20 12:00 AM	6.50	$ -
22	11/30/2020	-	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/25/20 12:00 AM	9.00	-
23	12/31/2020	-	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/24/20 12:00 AM	7.50	-
24									
25		$ -						-	$ -
26									
27									
28									
29	Payment date indicates the check date								
30									
31									
32									
33									
34									
35									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
FSA Medical

Line			Service Period		Total	Midpoint	Payment	(Lead) Lag	Weighted
No	Payroll Description	Amount	Start	End	Days	Service Period	Date	Days	Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ 82	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	10/1/20 12:00 AM	7.50	$ 614
4	10/3/2020	82	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/8/20 12:00 AM	7.50	614
5	10/10/2020	82	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/15/20 12:00 AM	7.50	614
6	10/17/2020	82	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/22/20 12:00 AM	7.50	614
7	10/24/2020	82	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/29/20 12:00 AM	7.50	614
8	10/31/2020	82	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/5/20 12:00 AM	7.50	614
9	11/7/2020	30	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	7.50	225
10	11/14/2020	30	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/19/20 12:00 AM	7.50	225
11	11/21/2020	30	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/25/20 12:00 AM	6.50	195
12	11/28/2020	30	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/3/20 12:00 AM	7.50	225
13	12/5/2020	30	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/10/20 12:00 AM	7.50	225
14	12/12/2020	30	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/17/20 12:00 AM	7.50	225
15									
16		$ 672						7.46	$ 5,006
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ -	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/23/20 12:00 AM	6.50	$ -
22	11/30/2020	-	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/25/20 12:00 AM	9.00	-
23	12/31/2020	-	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/24/20 12:00 AM	7.50	-
24									
25		$ -						-	$ -
26									
27									
28									
29	Payment date indicates the check date								
30									
31									
32									
33									
34									
35									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Taxed Life Insurance

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ 333	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	10/1/20 12:00 AM	7.50	$ 2,500
4	10/3/2020	333	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/8/20 12:00 AM	7.50	2,500
5	10/10/2020	333	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/15/20 12:00 AM	7.50	2,500
6	10/17/2020	333	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/22/20 12:00 AM	7.50	2,500
7	10/24/2020	333	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/29/20 12:00 AM	7.50	2,500
8	10/31/2020	333	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/5/20 12:00 AM	7.50	2,500
9	11/7/2020	333	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	7.50	2,500
10	11/14/2020	333	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/19/20 12:00 AM	7.50	2,500
11	11/21/2020	333	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/25/20 12:00 AM	6.50	2,167
12	11/28/2020	333	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/3/20 12:00 AM	7.50	2,500
13	12/5/2020	333	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/10/20 12:00 AM	7.50	2,500
14	12/12/2020	334	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/17/20 12:00 AM	7.50	2,505
15									
16		$ 4,001						7.42	$ 29,673
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ 571	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/23/20 12:00 AM	6.50	$ 3,714
22	11/30/2020	571	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/25/20 12:00 AM	9.00	5,142
23	12/31/2020	571	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/24/20 12:00 AM	7.50	4,285
24									
25		$ 1,714						7.67	$ 13,142
26									
27									
28									
29									
30									
31									
32									
33									
34									
35									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Auto Adjustment

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ -	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM	10/1/20 12:00 AM	152.00	$ -
4	10/3/2020	-	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM	10/8/20 12:00 AM	159.00	-
5	10/10/2020	-	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM	10/15/20 12:00 AM	166.00	-
6	10/17/2020	-	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM	10/22/20 12:00 AM	173.00	-
7	10/24/2020	-	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM	10/29/20 12:00 AM	180.00	-
8	10/31/2020	-	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM	11/5/20 12:00 AM	187.00	-
9	11/7/2020	-	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM	11/12/20 12:00 AM	194.00	-
10	11/14/2020	-	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM	11/19/20 12:00 AM	201.00	-
11	11/21/2020	-	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM	11/25/20 12:00 AM	207.00	-
12	11/28/2020	-	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM	12/3/20 12:00 AM	215.00	-
13	12/5/2020	-	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM	12/10/20 12:00 AM	222.00	-
14	12/12/2020	-	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM	12/17/20 12:00 AM	229.00	-
15									
16		$ -						-	$ -
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ -	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM	10/23/20 12:00 AM	174.00	-
22	11/30/2020	7,492	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM	11/25/20 12:00 AM	207.00	1,550,937
23	12/31/2020	3,869	11/1/19 12:00 AM	11/1/20 12:00 AM	366	5/2/20 12:00 AM	12/24/20 12:00 AM	236.00	913,200
24									
25		$ 11,362						216.88	$ 2,464,137
26									
27									
28									
29	The Auto amount represents the imputed value for the personal use of a company car that is added to the employees gross wages on their W-2.								
30	Employee is responsible for taxes. Earnings are grossed up.								
31	Amount is added to earnings and deductions.								
32									
33									
34									
35									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Education Aid

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ -	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	10/1/20 12:00 AM	7.50	$ -
4	10/3/2020	-	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/8/20 12:00 AM	7.50	-
5	10/10/2020	-	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/15/20 12:00 AM	7.50	-
6	10/17/2020	-	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/22/20 12:00 AM	7.50	-
7	10/24/2020	-	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/29/20 12:00 AM	7.50	-
8	10/31/2020	-	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/5/20 12:00 AM	7.50	-
9	11/7/2020	-	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	7.50	-
10	11/14/2020	-	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/19/20 12:00 AM	7.50	-
11	11/21/2020	-	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/25/20 12:00 AM	6.50	-
12	11/28/2020	-	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/3/20 12:00 AM	7.50	-
13	12/5/2020	-	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/10/20 12:00 AM	7.50	-
14	12/12/2020	-	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/17/20 12:00 AM	7.50	-
15									
16		$ -						-	$ -
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ -	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/23/20 12:00 AM	6.50	$ -
22	11/30/2020	-	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/25/20 12:00 AM	9.00	-
23	12/31/2020	-	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/24/20 12:00 AM	7.50	-
24									
25		$ -						-	$ -
26									
27									
28									
29									
30									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
ADP Payroll Lead Lag Summary

Line No	Gross Payroll Items	Amount	(Lead) Lag Days	Weighted Dollar Days
1				
2	**Weekly**			
3	Net Payroll	$ 745,764	6.50	$ 4,846,548
	Misc.	5,960	6.58	39,236
4	Federal Witholding	164,407	6.50	1,069,157
5	FICA Witholding	59,602	6.51	388,131
6	Medicare	16,225	6.50	105,472
7	MA & ME State W/H	3,690	6.50	23,969
8				
9	Total Weekly Payroll	$ 995,648	6.50	$ 6,472,512
10				
11				
12	**Monthly**			
13	Net Payroll	$ 215,953	5.66	$1,221,298
14	Misc.	-	-	-
15	Federal Witholding	38,137	5.66	216,021
16	FICA Witholding	15,542	5.68	88,256
17	Medicare	3,213	8.41	27,035
18	MA & ME State W/H	-	-	-
19				
20	Total Monthly Payroll	$ 272,845	5.69	$ 1,552,611
21				
22				
23	Total Weekly & Monthly	$ 1,268,493	6.33	$ 8,025,123
24				
25				
26	**Incentive Pay**			
27	Net Payroll	$ 97,265	223.50	$ 21,738,757
28	Misc.	-	-	-
29	Federal Witholding	30,501	223.50	6,817,036
30	FICA Witholding	8,814	223.50	1,970,027
31	Medicare	2,061	223.50	460,730
32	MA & ME State W/H	-	-	-
33				
34	Total Incentive Payroll	$ 138,642	223.50	$ 30,986,550
35				
36				
37				
38		Annual		
39	Employer Payroll Taxes	Expense		
40	FICA Employer Weekly	$ 344,978	6.51	$ 2,246,525
41	FICA Employer Monthly	92,873	5.68	527,396
42	FICA Employer Incentive	10,876	223.50	2,430,757
43	Medicare Employer Weekly	67,461	6.50	438,536
44	Mecicare Employer Monthly	18,519	5.69	105,364
45	Mecicare Employer Incentive	2,061	223.50	460,732
46	FUI Employer Weekly	1,833	4.50	8,249
47	FUI Employer Monthly	735	4.50	3,307
48	FUI Employer Incentive	42	223.50	9,425
49	SUI Employer Weekly	651	6.50	4,234
50	SUI Employer Monthly	226	5.09	1,152
51	SUI Employer incentive	69	223.50	15,451
52				
53	Total Employer Payroll Taxes	$ 540,326	11.57	$ 6,251,127
54				
55				
56	Total FICA Taxes	$ 448,727	11.60	$ 5,204,678
57				
58	Total Medicare Taxes	$ 88,042	11.41	$ 1,004,631
59				
60	Total Federal Unemployment Taxes	$ 2,610	8.04	$ 20,981
61				
62	Total State Unemployment Taxes	$ 947	22.01	$ 20,837
63				
64				
65				

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Total Payroll Service

Line No	Payroll Description	Grand Total Payroll Amount	Total ADP Payroll Items	Total Transfer to ADP	Difference	Total Payroll Deductions
1	**Weekly**					
2						
3	9/26/2020	$ 94,184.360	$ 79,356.310	$ 79,356	-	$ 72,995
4	10/3/2020	$ 89,557.090	$ 75,339.170	75,339	-	69,277
5	10/10/2020	$ 120,604.950	$ 104,704.290	104,704	-	96,624
6	10/17/2020	$ 94,378.710	$ 80,313.760	80,314	-	74,095
7	10/24/2020	$ 87,218.990	$ 73,313.450	73,313	-	67,657
8	10/31/2020	$ 93,518.470	$ 78,822.300	78,822	-	72,739
9	11/7/2020	$ 102,249.540	$ 87,705.990	87,706	-	81,030
10	11/14/2020	$ 97,805.140	$ 83,526.850	83,527	-	77,394
11	11/21/2020	$ 100,706.670	$ 86,672.650	86,673	-	80,726
12	11/28/2020	$ 101,388.300	$ 87,761.180	87,761	-	82,358
13	12/5/2020	$ 116,494.820	$ 101,971.970	101,972	-	95,825
14	12/12/2020	$ 147,796.120	$ 132,027.400	132,027	-	124,926
15						
16						
17		$ 1,245,903	$ 1,071,515	$ 1,071,515		$ 995,648
18						
19						
20	**Monthly**					
21						
22	10/31/2020	$ 117,443	$ 99,075	$ 99,075	-	$ 92,345
23	11/30/2020	123,796	97,476	97,476	-	88,904
24	12/31/2020	120,808	98,199	98,199	-	93,183
25						
26		$ 362,046	$ 294,750	$ 294,750		$ 274,432
27						
28						
29	**Incentive Pay**					
30						
31	Incentive Pay Feb	$ 153,155	$ 149,629	149,629	-	$ 138,642
32						
33		$ 153,155	$ 149,629	$ 149,629		$ 138,642
34						
35						
36	Total	$ 1,761,104	$ 1,515,895	$ 1,515,895		$ 1,408,723
37						
38						
39						
40						

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Net Payroll

Line No	Payroll Description	Net Payroll Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Wire Transfer Date	(Lead) Lag Days	Weighted Dollar Days	Pay Date
1	**Weekly**									
2										
3	9/26/2020	$ 54,721	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	9/30/20 12:00 AM	6.50	$ 355,687	10/1/20 12:00 AM
4	10/3/2020	52,122	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/7/20 12:00 AM	6.50	338,795	10/8/20 12:00 AM
5	10/10/2020	70,431	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/14/20 12:00 AM	6.50	457,801	10/15/20 12:00 AM
6	10/17/2020	55,595	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/21/20 12:00 AM	6.50	361,366	10/22/20 12:00 AM
7	10/24/2020	51,227	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/28/20 12:00 AM	6.50	332,973	10/29/20 12:00 AM
8	10/31/2020	54,858	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/4/20 12:00 AM	6.50	356,578	11/5/20 12:00 AM
9	11/7/2020	60,211	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	7.50	451,586	11/12/20 12:00 AM
10	11/14/2020	58,167	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/18/20 12:00 AM	6.50	378,087	11/19/20 12:00 AM
11	11/21/2020	61,127	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/24/20 12:00 AM	5.50	336,201	11/25/20 12:00 AM
12	11/28/2020	62,725	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/2/20 12:00 AM	6.50	407,710	12/3/20 12:00 AM
13	12/5/2020	72,035	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/9/20 12:00 AM	6.50	468,226	12/10/20 12:00 AM
14	12/12/2020	92,544	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/16/20 12:00 AM	6.50	601,538	12/17/20 12:00 AM
15										
16		$ 745,764						6.50	$ 4,846,548	
17										
18										
19	**Monthly**									
20										
21	10/31/2020	72,905	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/21/20 12:00 AM	4.50	328,071	10/23/20 12:00 AM
22	11/30/2020	70,973	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/23/20 12:00 AM	7.00	496,809	11/25/20 12:00 AM
23	12/31/2020	72,076	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/22/20 12:00 AM	5.50	396,418	12/24/20 12:00 AM
24										
25		$ 215,953						5.66	$ 1,221,298	
26										
27										
28	**Incentive Pay**									
29										
30	Incentive Pay Feb	$ 97,265	1/1/19 12:00 AM	1/1/20 12:00 AM	365	7/2/19 12:00 PM	2/11/20 12:00 AM	223.50	$ 21,738,757	2/13/20 12:00 AM
31										
32		$ 97,265						223.50	$ 21,738,757	
33										
34										
35										

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Misc.

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Wire Transfer Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ 497	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	9/30/20 12:00 AM	6.50	$ 3,228
4	10/3/2020	497	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/7/20 12:00 AM	6.50	3,228
5	10/10/2020	497	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/14/20 12:00 AM	6.50	3,228
6	10/17/2020	497	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/21/20 12:00 AM	6.50	3,228
7	10/24/2020	497	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/28/20 12:00 AM	6.50	3,228
8	10/31/2020	497	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/4/20 12:00 AM	6.50	3,228
9	11/7/2020	497	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	7.50	3,725
10	11/14/2020	497	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/18/20 12:00 AM	6.50	3,228
11	11/21/2020	497	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/24/20 12:00 AM	5.50	2,732
12	11/28/2020	497	11/21/20 12:00 AM	11/28/20 12:00 AM	7	11/24/20 12:00 PM	12/2/20 12:00 AM	7.50	3,725
13	12/5/2020	497	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/9/20 12:00 AM	6.50	3,228
14	12/12/2020	497	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/16/20 12:00 AM	6.50	3,228
15									
16		$ 5,960						6.58	$ 39,236
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ -	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/21/20 12:00 AM	4.50	$ -
22	11/30/2020	-	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/23/20 12:00 AM	7.00	-
23	12/31/2020	-	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/22/20 12:00 AM	5.50	-
24									
25		$ -						-	$ -
26									
27									
28	**Incentive Pay**								
29									
30	Incentive Pay Feb	$ -	1/1/19 12:00 AM	1/1/20 12:00 AM	365	7/2/19 12:00 PM	2/11/20 12:00 AM	223.50	$ -
31									
32		$ -						-	$ -
33									
34									
35									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Federal Witholding

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Wire Transfer Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ 11,139	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	9/30/20 12:00 AM	6.50	$ 72,404
4	10/3/2020	10,347	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/7/20 12:00 AM	6.50	67,256
5	10/10/2020	17,091	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/14/20 12:00 AM	6.50	111,090
6	10/17/2020	11,513	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/21/20 12:00 AM	6.50	74,835
7	10/24/2020	10,006	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/28/20 12:00 AM	6.50	65,041
8	10/31/2020	11,013	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/4/20 12:00 AM	6.50	71,584
9	11/7/2020	13,347	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	7.50	100,102
10	11/14/2020	12,333	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/18/20 12:00 AM	6.50	80,167
11	11/21/2020	12,838	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/24/20 12:00 AM	5.50	70,609
12	11/28/2020	13,469	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/2/20 12:00 AM	6.50	87,548
13	12/5/2020	16,817	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/9/20 12:00 AM	6.50	109,313
14	12/12/2020	24,494	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/16/20 12:00 AM	6.50	159,209
15									
16		$ 164,407						6.50	$ 1,069,157
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ 12,672	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/21/20 12:00 AM	4.50	$ 57,025
22	11/30/2020	12,626	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/23/20 12:00 AM	7.00	88,383
23	12/31/2020	12,839	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/22/20 12:00 AM	5.50	70,614
24									
25		$ 38,137						5.66	$ 216,021
26									
27									
28	**Incentive Pay**								
29									
30	Incentive Pay Feb	$ 30,501	1/1/19 12:00 AM	1/1/20 12:00 AM	365	7/2/19 12:00 PM	2/11/20 12:00 AM	223.50	$ 6,817,036
31									
32		$ 30,501						223.50	$ 6,817,036
33									
34									
35									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
FICA Witholding

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Wire Transfer Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ 5,146	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	9/30/20 12:00 AM	6.50	$ 33,452
4	10/3/2020	4,903	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/7/20 12:00 AM	6.50	31,869
5	10/10/2020	6,499	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/14/20 12:00 AM	6.50	42,243
6	10/17/2020	5,003	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/21/20 12:00 AM	6.50	32,519
7	10/24/2020	4,536	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/28/20 12:00 AM	6.50	29,486
8	10/31/2020	4,879	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/4/20 12:00 AM	6.50	31,711
9	11/7/2020	5,351	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	7.50	40,130
10	11/14/2020	4,862	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/18/20 12:00 AM	6.50	31,600
11	11/21/2020	4,630	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/24/20 12:00 AM	5.50	25,467
12	11/28/2020	4,068	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/2/20 12:00 AM	6.50	26,439
13	12/5/2020	4,606	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/9/20 12:00 AM	6.50	29,938
14	12/12/2020	5,119	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/16/20 12:00 AM	6.50	33,277
15									
16		$ 59,602						6.51	$ 388,131
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ 5,181	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/21/20 12:00 AM	4.50	$ 23,316
22	11/30/2020	5,305	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/23/20 12:00 AM	7.00	37,138
23	12/31/2020	5,055	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/22/20 12:00 AM	5.50	27,802
24									
25		$ 15,542						5.68	$ 88,256
26									
27									
28	**Incentive Pay**								
29									
30	Incentive Pay Feb	8,814	1/1/19 12:00 AM	1/1/20 12:00 AM	365	7/2/19 12:00 PM	2/11/20 12:00 AM	223.50	$ 1,970,027
31									
32		$ 8,814						223.50	$ 1,970,027
33									
34									
35									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Medicare

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Wire Transfer Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ 1,204	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	9/30/20 12:00 AM	6.50	$ 7,824
4	10/3/2020	1,147	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/7/20 12:00 AM	6.50	7,453
5	10/10/2020	1,564	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/14/20 12:00 AM	6.50	10,165
6	10/17/2020	1,215	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/21/20 12:00 AM	6.50	7,900
7	10/24/2020	1,120	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/28/20 12:00 AM	6.50	7,278
8	10/31/2020	1,205	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/4/20 12:00 AM	6.50	7,831
9	11/7/2020	1,325	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	7.50	9,939
10	11/14/2020	1,271	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/18/20 12:00 AM	6.50	8,264
11	11/21/2020	1,316	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/24/20 12:00 AM	5.50	7,239
12	11/28/2020	1,335	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/2/20 12:00 AM	6.50	8,679
13	12/5/2020	1,541	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/9/20 12:00 AM	6.50	10,016
14	12/12/2020	1,982	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/16/20 12:00 AM	6.50	12,884
15									
16		$ 16,225						6.50	$ 105,472
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ 1,539	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/21/20 12:00 AM	4.50	$ 6,924
22	11/30/2020	1,626	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/23/20 12:00 AM	7.00	11,382
23	12/31/2020	1,587	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/22/20 12:00 AM	5.50	8,729
24									
25		$ 3,213						8.41	$ 27,035
26									
27									
28	**Incentive Pay**								
29									
30	Incentive Pay Feb	$ 2,061	1/1/19 12:00 AM	1/1/20 12:00 AM	365	7/2/19 12:00 PM	2/11/20 12:00 AM	223.50	$ 460,730
31									
32		$ 2,061						223.50	$ 460,730
33									
34									
35									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
MA & ME State W/H

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Wire Transfer Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ 289	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	9/30/20 12:00 AM	6.50	$ 1,875
4	10/3/2020	262	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/7/20 12:00 AM	6.50	1,702
5	10/10/2020	543	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/14/20 12:00 AM	6.50	3,527
6	10/17/2020	273	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/21/20 12:00 AM	6.50	1,772
7	10/24/2020	272	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/28/20 12:00 AM	6.50	1,766
8	10/31/2020	288	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/4/20 12:00 AM	6.50	1,869
9	11/7/2020	299	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	7.50	2,245
10	11/14/2020	264	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/18/20 12:00 AM	6.50	1,715
11	11/21/2020	318	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/24/20 12:00 AM	5.50	1,747
12	11/28/2020	265	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/2/20 12:00 AM	6.50	1,726
13	12/5/2020	330	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/9/20 12:00 AM	6.50	2,144
14	12/12/2020	289	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/16/20 12:00 AM	6.50	1,881
15									
16		$ 3,690						6.50	$ 23,969
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ -	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/21/20 12:00 AM	4.50	$ -
22	11/30/2020	-	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/23/20 12:00 AM	7.00	-
23	12/31/2020	-	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/22/20 12:00 AM	5.50	-
24									
25		$ -						-	$ -
26									
27									
28	**Incentive Pay**								
29									
30	Incentive Pay Feb	$ -	1/1/19 12:00 AM	1/1/20 12:00 AM	365	7/2/19 12:00 PM	2/11/20 12:00 AM	223.50	$ -
31									
32		$ -						-	$ -
33									
34									
35									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
FICA Employer

Line No	Payroll Description		Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Wire Transfer Date	(Lead) Lag Days		Weighted Dollar Days
1	**Weekly**										
2											
3	9/26/2020	$	5,146	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	9/30/20 12:00 AM	6.50	$	33,452
4	10/3/2020		4,903	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/7/20 12:00 AM	6.50		31,869
5	10/10/2020		6,499	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/14/20 12:00 AM	6.50		42,243
6	10/17/2020		5,003	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/21/20 12:00 AM	6.50		32,519
7	10/24/2020		4,536	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/28/20 12:00 AM	6.50		29,486
8	10/31/2020		4,879	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/4/20 12:00 AM	6.50		31,712
9	11/7/2020		5,351	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	7.50		40,129
10	11/14/2020		4,861	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/18/20 12:00 AM	6.50		31,600
11	11/21/2020		4,630	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/24/20 12:00 AM	5.50		25,467
12	11/28/2020		4,068	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/2/20 12:00 AM	6.50		26,439
13	12/5/2020		4,606	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/9/20 12:00 AM	6.50		29,938
14	12/12/2020		5,120	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/16/20 12:00 AM	6.50		33,277
15											
16		$	59,602						6.51	$	388,130
17											
18											
19	**Monthly**										
20											
21	10/31/2020	$	5,181	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/21/20 12:00 AM	4.50	$	23,316
22	11/30/2020		5,305	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/23/20 12:00 AM	7.00		37,138
23	12/31/2020		5,055	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/22/20 12:00 AM	5.50		27,802
24											
25		$	15,542						5.68	$	88,256
26											
27											
28	**Incentive Pay**										
29											
30	Incentive Pay Feb		8,814	1/1/19 12:00 AM	1/1/20 12:00 AM	365	7/2/19 12:00 PM	2/11/20 12:00 AM	223.50	$	1,970,012
31											
32		$	8,814						223.50	$	1,970,012
33											
34											
35											

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
Medicare Employer

Line No	Payroll Description		Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Wire Transfer Date	(Lead) Lag Days		Weighted Dollar Days
1	**Weekly**										
2											
3	9/26/2020	$	1,204	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	9/30/20 12:00 AM	6.50	$	7,824
4	10/3/2020		1,147	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/7/20 12:00 AM	6.50		7,453
5	10/10/2020		1,564	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/14/20 12:00 AM	6.50		10,165
6	10/17/2020		1,215	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/21/20 12:00 AM	6.50		7,900
7	10/24/2020		1,120	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/28/20 12:00 AM	6.50		7,278
8	10/31/2020		1,205	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/4/20 12:00 AM	6.50		7,831
9	11/7/2020		1,325	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	7.50		9,939
10	11/14/2020		1,271	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/18/20 12:00 AM	6.50		8,264
11	11/21/2020		1,316	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/24/20 12:00 AM	5.50		7,239
12	11/28/2020		1,335	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/2/20 12:00 AM	6.50		8,679
13	12/5/2020		1,541	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/9/20 12:00 AM	6.50		10,016
14	12/12/2020		1,982	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/16/20 12:00 AM	6.50		12,884
15											
16		$	16,225						6.50	$	105,472
17											
18											
19	**Monthly**										
20											
21	10/31/2020	$	1,539	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/21/20 12:00 AM	4.50	$	6,924
22	11/30/2020		1,626	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/23/20 12:00 AM	7.00		11,382
23	12/31/2020		1,587	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/22/20 12:00 AM	5.50		8,729
24											
25		$	4,752						5.69	$	27,035
26											
27											
28	**Incentive Pay**										
29											
30	Incentive Pay Feb	$	2,061	1/1/19 12:00 AM	1/1/20 12:00 AM	365	7/2/19 12:00 PM	2/11/20 12:00 AM	223.50	$	460,732
31											
32		$	2,061						223.50	$	460,732
33											
34											
35											

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
FUI Employer

Line No	Payroll Description	Net Payroll Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Wire Transfer Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ -	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	9/30/20 12:00 AM	6.50	$ -
4	10/3/2020	-	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/7/20 12:00 AM	6.50	-
5	10/10/2020	-	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/14/20 12:00 AM	6.50	-
6	10/17/2020	-	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/21/20 12:00 AM	6.50	-
7	10/24/2020	-	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/28/20 12:00 AM	6.50	-
8	10/31/2020	-	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/4/20 12:00 AM	6.50	-
9	11/7/2020	-	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	7.50	-
10	11/14/2020	-	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/18/20 12:00 AM	6.50	-
11	11/21/2020	-	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/24/20 12:00 AM	5.50	-
12	11/28/2020	-	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/2/20 12:00 AM	6.50	-
13	12/5/2020	-	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/9/20 12:00 AM	6.50	-
14	12/12/2020	-	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/16/20 12:00 AM	6.50	-
15									
16		$ -						-	$ -
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ 12	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/21/20 12:00 AM	4.50	$ 52
22	11/30/2020	-	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/23/20 12:00 AM	7.00	-
23	12/31/2020	-	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/22/20 12:00 AM	5.50	-
24									
25		$ 12						4.50	$ 52
26									
27									
28	**Incentive Pay**								
29									
30	Incentive Pay Feb	$ 42	1/1/19 12:00 AM	1/1/20 12:00 AM	365	7/2/19 12:00 PM	2/11/20 12:00 AM	223.50	$ 9,425
31									
32		$ 42						223.50	$ 9,425
33									
34									
35									

Unitil Energy Systems, Inc.
Calculation of Payroll Lag Days
12 Months Ended Dec 31, 2020
SUI Employer

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Wire Transfer Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	9/26/2020	$ 11	9/20/20 12:00 AM	9/27/20 12:00 AM	7	9/23/20 12:00 PM	9/30/20 12:00 AM	6.50	$ 70
4	10/3/2020	12	9/27/20 12:00 AM	10/4/20 12:00 AM	7	9/30/20 12:00 PM	10/7/20 12:00 AM	6.50	79
5	10/10/2020	18	10/4/20 12:00 AM	10/11/20 12:00 AM	7	10/7/20 12:00 PM	10/14/20 12:00 AM	6.50	117
6	10/17/2020	-	10/11/20 12:00 AM	10/18/20 12:00 AM	7	10/14/20 12:00 PM	10/21/20 12:00 AM	6.50	-
7	10/24/2020	-	10/18/20 12:00 AM	10/25/20 12:00 AM	7	10/21/20 12:00 PM	10/28/20 12:00 AM	6.50	-
8	10/31/2020	-	10/25/20 12:00 AM	11/1/20 12:00 AM	7	10/28/20 12:00 PM	11/4/20 12:00 AM	6.50	-
9	11/7/2020	-	11/1/20 12:00 AM	11/8/20 12:00 AM	7	11/4/20 12:00 PM	11/12/20 12:00 AM	7.50	-
10	11/14/2020	-	11/8/20 12:00 AM	11/15/20 12:00 AM	7	11/11/20 12:00 PM	11/18/20 12:00 AM	6.50	-
11	11/21/2020	-	11/15/20 12:00 AM	11/22/20 12:00 AM	7	11/18/20 12:00 PM	11/24/20 12:00 AM	5.50	-
12	11/28/2020	-	11/22/20 12:00 AM	11/29/20 12:00 AM	7	11/25/20 12:00 PM	12/2/20 12:00 AM	6.50	-
13	12/5/2020	-	11/29/20 12:00 AM	12/6/20 12:00 AM	7	12/2/20 12:00 PM	12/9/20 12:00 AM	6.50	-
14	12/12/2020	-	12/6/20 12:00 AM	12/13/20 12:00 AM	7	12/9/20 12:00 PM	12/16/20 12:00 AM	6.50	-
15									
16		$ 41						6.50	$ 266
17									
18									
19	**Monthly**								
20									
21	10/31/2020	$ 47	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	10/21/20 12:00 AM	4.50	$ 211
22	11/30/2020	15	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	11/23/20 12:00 AM	7.00	102
23	12/31/2020	-	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	12/22/20 12:00 AM	5.50	-
24									
25		$ 61						5.09	$ 313
26									
27									
28	**Incentive Pay**								
29									
30	Incentive Pay Feb	$ 69	1/1/19 12:00 AM	1/1/20 12:00 AM	365	7/2/19 12:00 PM	2/11/20 12:00 AM	223.50	$ 15,451
31									
32		$ 69						223.50	$ 15,451
33									
34									
35									

Unitil Energy Systems, Inc.
Calculation of Pension & Benefits Lead Lag Days
12 Months Ended Dec 31, 2020
Summary of Employee Benefits Acct 926

ELECTRIC

Line No		Description of Benefit	Amount Expensed	(Lead) Lag Days	Test Period Weighted Dollar Days
1		Empl Pension Fund Services	$ 6,582	147.07	$ 968,000
2	Cap	Employee Pension 410K	279,985	9.35	2,617,377
3		401K Capitalized	(169,498)	9.35	(1,584,520)
4	Cap	Health Insurance Medical Only	886,816	51.30	45,493,647
5		Health Ins - Emp Contr - Medical Only	(203,241)	51.30	(10,426,264)
6		Health Insurance - Drug Subsidy	(28,556)	338.33	(9,661,282)
7	Cap	Dental Insurance	52,306	51.30	2,683,295
8		Dental Insurance - Emp Contribution	(12,021)	51.30	(616,683)
9		Vision	9,038	30.00	271,134
10		Vision - EE Contr	(2,909)	30.00	(87,262)
11	Cap	Empl Benefit - Life Insurance	25,251	7.46	188,297
12	Cap	AD&D Insurance	12,478	7.63	95,262
13	Cap	LTD Insurance	30,935	56.87	1,759,359
14		Employee Benefit Accrual Adj	7,748	49.83	386,096
15		Benefit Cost Capitalized	(628,755)	49.83	(31,332,061)
16		Empl Benefits Other	21,591	54.93	1,186,002
17					
18		Total Employee Benefits	$ 287,748		$ 1,940,398
19					
20		Total Base Rate Employee Benefits	$ 287,748	6.74	$ 1,940,398
21					
22		Totl 401k used for Capitalized Items	$ 279,985	9.35	$ 2,617,377
23					
24		Total Direct Benefits used for Capitalized Items	$ 1,007,786	49.83	$ 50,219,861
25					
26					
27		Health & Dental Lags	$ 695,304	39.51	$ 27,472,713
28					
29					
30					

ELECTRIC

Acct: **102003009261000**

Unitil Energy Systems, Inc.
Pensions & Benefits Calculation of (Lead) Lag
Empl Pension Fund Services
12 Months Ended Dec 31, 2020

Line No	Month	Expense Amount	Service From	Service To	Total Days	Mid-Point Calculation Date	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1	January	$ -	-	-	-			-	$ -
2	February	165	12/1/19 12:00 AM	1/1/20 12:00 AM	31	12/16/19 12:00 PM	2/13/20 12:00 AM	58.50	9,653
3	March	-	-	-	-			-	-
4	April	96	10/1/19 12:00 AM	11/1/19 12:00 AM	31	10/16/19 12:00 PM	4/16/20 12:00 AM	182.50	17,566
5	April	179	12/1/19 12:00 AM	1/1/20 12:00 AM	31	12/16/19 12:00 PM	4/16/20 12:00 AM	121.50	21,718
6	April	139	10/1/19 12:00 AM	1/1/20 12:00 AM	92	11/16/19 12:00 AM	4/16/20 12:00 AM	152.00	21,072
7	April	1,596	7/1/19 12:00 AM	10/1/19 12:00 AM	92	8/16/19 12:00 AM	4/16/20 12:00 AM	244.00	389,404
8	April	1,848	10/1/19 12:00 AM	1/1/20 12:00 AM	92	11/16/19 12:00 AM	4/16/20 12:00 AM	152.00	280,952
9	May	1,585	1/1/20 12:00 AM	4/1/20 12:00 AM	91	2/15/20 12:00 PM	5/14/20 12:00 AM	88.50	140,244
10	June	-	-	-	-			-	-
11	July	-	-	-	-			-	-
12	August	-	-	-	-			-	-
13	September	900	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	9/24/20 12:00 AM	84.00	75,600
14	October	74	4/1/20 12:00 AM	7/1/20 12:00 AM	91	5/16/20 12:00 PM	10/22/20 12:00 AM	158.50	11,791
15	November	-	-	-	-			-	-
16	December	-	-	-	-			-	-
17									
18		$ 6,582						147.07	$ 968,000
19									
20									
21	Misc payments to NYLIM and Diversified for pension fund services								
22									
23									
24									
25									

Unitil Energy Systems, Inc.
Pensions & Benefits Calculation of (Lead) Lag
Employee Pension 410K
12 Months Ended Dec 31, 2020

ELECTRIC

Acct: **102003009260100**

Line No	Month	Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days	Weighted Dollar Days
1	January	$ 27,154	1/1/20 12:00 AM	2/1/20 12:00 AM	31	9.35	$ 253,845
2	February	23,304	2/1/20 12:00 AM	3/1/20 12:00 AM	29	9.35	217,855
3	March	20,259	3/1/20 12:00 AM	4/1/20 12:00 AM	31	9.35	189,383
4	April	23,270	4/1/20 12:00 AM	5/1/20 12:00 AM	30	9.35	217,533
5	May	20,430	5/1/20 12:00 AM	6/1/20 12:00 AM	31	9.35	190,986
6	June	21,234	6/1/20 12:00 AM	7/1/20 12:00 AM	30	9.35	198,499
7	July	25,910	7/1/20 12:00 AM	8/1/20 12:00 AM	31	9.35	242,215
8	August	21,343	8/1/20 12:00 AM	9/1/20 12:00 AM	31	9.35	199,522
9	September	22,353	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9.35	208,959
10	October	26,250	10/1/20 12:00 AM	11/1/20 12:00 AM	31	9.35	245,392
11	November	22,009	11/1/20 12:00 AM	12/1/20 12:00 AM	30	9.35	205,746
12	December	26,469	12/1/20 12:00 AM	1/1/21 12:00 AM	31	9.35	247,441
13							
14		$ 279,985			366	9.35	$ 2,617,377
15							
16							
17	Payments to New York Life for 401k - employee match						
18							
19	Lag Days are from Non ADP Payroll Lead Lag.						
20							
21							
22							
23							
24							
25							

Unitil Energy Systems, Inc.
ELECTRIC Pensions & Benefits Calculation of (Lead) Lag
401K Capitalized
Acct: **102010009260101** 12 Months Ended Dec 31, 2020

Line No	Month	Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days	Weighted Dollar Days
1	January	$ (17,292)	1/1/20 12:00 AM	2/1/20 12:00 AM	31	9.35	$ (161,646)
2	February	(14,841)	2/1/20 12:00 AM	3/1/20 12:00 AM	29	9.35	(138,736)
3	March	(12,900)	3/1/20 12:00 AM	4/1/20 12:00 AM	31	9.35	(120,595)
4	April	(14,818)	4/1/20 12:00 AM	5/1/20 12:00 AM	30	9.35	(138,527)
5	May	(13,010)	5/1/20 12:00 AM	6/1/20 12:00 AM	31	9.35	(121,623)
6	June	(13,522)	6/1/20 12:00 AM	7/1/20 12:00 AM	30	9.35	(126,403)
7	July	(16,500)	7/1/20 12:00 AM	8/1/20 12:00 AM	31	9.35	(154,243)
8	August	(13,591)	8/1/20 12:00 AM	9/1/20 12:00 AM	31	9.35	(127,053)
9	September	(14,235)	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9.35	(133,068)
10	October	(16,715)	10/1/20 12:00 AM	11/1/20 12:00 AM	31	9.35	(156,260)
11	November	(14,015)	11/1/20 12:00 AM	12/1/20 12:00 AM	30	9.35	(131,017)
12	December	(8,060)	12/1/20 12:00 AM	1/1/21 12:00 AM	31	9.35	(75,348)
13							
14		$ (169,498)			366	9.35	$ (1,584,520)
15							
16							
17	Capitalization of 401K benefits						
18							
19	Lag Days are from Non ADP Payroll Lead Lag.						
20							
21							
22							
23							
24							
25							

Unitil Energy Systems, Inc.
Pensions & Benefits Calculation of (Lead) Lag
Health Insurance Medical Only
12 Months Ended Dec 31, 2020

ELECTRIC

Acct: **102003009260300**

Line No	Month	Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days	Weighted Dollar Days
1	January	$ 113,773	1/1/20 12:00 AM	2/1/20 12:00 AM	31	51.30	$ 5,836,555
2	February	91,273	2/1/20 12:00 AM	3/1/20 12:00 AM	29	51.30	4,682,305
3	March	173,915	3/1/20 12:00 AM	4/1/20 12:00 AM	31	51.30	8,921,849
4	April	91,273	4/1/20 12:00 AM	5/1/20 12:00 AM	30	51.30	4,682,305
5	May	91,273	5/1/20 12:00 AM	6/1/20 12:00 AM	31	51.30	4,682,305
6	June	(136,015)	6/1/20 12:00 AM	7/1/20 12:00 AM	30	51.30	(6,977,550)
7	July	91,273	7/1/20 12:00 AM	8/1/20 12:00 AM	31	51.30	4,682,305
8	August	76,300	8/1/20 12:00 AM	9/1/20 12:00 AM	31	51.30	3,914,205
9	September	(51,581)	9/1/20 12:00 AM	10/1/20 12:00 AM	30	51.30	(2,646,117)
10	October	190,291	10/1/20 12:00 AM	11/1/20 12:00 AM	31	51.30	9,761,917
11	November	63,767	11/1/20 12:00 AM	12/1/20 12:00 AM	30	51.30	3,271,264
12	December	91,273	12/1/20 12:00 AM	1/1/21 12:00 AM	31	51.30	4,682,305
13							
14		$ 886,816			366	51.30	$ 45,493,647
15							
16							
17	Health Insurance Accruals						
18							
19	Lag Days are from Non ADP Payroll Lead Lag.						
20							
21							
22							
23							
24							
25							

Unitil Energy Systems, Inc.
Pensions & Benefits Calculation of (Lead) Lag
Health Ins - Emp Contr - Medical Only
12 Months Ended Dec 31, 2020

ELECTRIC

Acct: **102003009260301**

Line No	Month	Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days	Weighted Dollar Days
1	January	$ (19,410)	1/1/20 12:00 AM	2/1/20 12:00 AM	31	51.30	$ (995,714)
2	February	(13,235)	2/1/20 12:00 AM	3/1/20 12:00 AM	29	51.30	(678,954)
3	March	(18,007)	3/1/20 12:00 AM	4/1/20 12:00 AM	31	51.30	(923,769)
4	April	(17,267)	4/1/20 12:00 AM	5/1/20 12:00 AM	30	51.30	(885,806)
5	May	(15,865)	5/1/20 12:00 AM	6/1/20 12:00 AM	31	51.30	(813,887)
6	June	(17,795)	6/1/20 12:00 AM	7/1/20 12:00 AM	30	51.30	(912,878)
7	July	(17,584)	7/1/20 12:00 AM	8/1/20 12:00 AM	31	51.30	(902,058)
8	August	(15,643)	8/1/20 12:00 AM	9/1/20 12:00 AM	31	51.30	(802,478)
9	September	(17,868)	9/1/20 12:00 AM	10/1/20 12:00 AM	30	51.30	(916,615)
10	October	(17,218)	10/1/20 12:00 AM	11/1/20 12:00 AM	31	51.30	(883,260)
11	November	(16,078)	11/1/20 12:00 AM	12/1/20 12:00 AM	30	51.30	(824,790)
12	December	(17,272)	12/1/20 12:00 AM	1/1/21 12:00 AM	31	51.30	(886,056)
13							
14		$ (203,241)			366	51.30	$ (10,426,264)
15							
16							
17	Employee Contributions (through withholdings) for Medical						
18							
19	Lag Days are from Non ADP Payroll Lead Lag.						
20							
21							
22							
23							
24							
25							

ELECTRIC

Acct: **102003009260303**

Unitil Energy Systems, Inc.
Pensions & Benefits Calculation of (Lead) Lag
Health Insurance - Drug Subsidy
12 Months Ended Dec 31, 2020

Line No	Month	Expense Amount	Service From	Service To	Total Days	Mid-Point Calculation Date	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1	January	$ (2,229)	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	5/31/21 12:00 AM	333.00	$ (742,144)
2	February	(1,863)	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	6/1/21 12:00 AM	334.00	(622,295)
3	March	(2,229)	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	6/2/21 12:00 AM	335.00	(746,601)
4	April	(2,105)	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	6/3/21 12:00 AM	336.00	(707,136)
5	May	(5,256)	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	6/4/21 12:00 AM	337.00	(1,771,107)
6	June	(2,106)	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	6/5/21 12:00 AM	338.00	(711,875)
7	July	(2,107)	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	6/6/21 12:00 AM	339.00	(714,331)
8	August	(2,229)	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	6/7/21 12:00 AM	340.00	(757,744)
9	September	(2,229)	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	6/8/21 12:00 AM	341.00	(759,973)
10	October	(2,229)	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	6/9/21 12:00 AM	342.00	(762,202)
11	November	(1,867)	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	6/10/21 12:00 AM	343.00	(640,299)
12	December	(2,109)	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	6/11/21 12:00 AM	344.00	(725,575)
13									
14		$ (28,556)						338.33	$ (9,661,282)
15									
16									
17	General Accounting entries to accrue for annual drug subsidy receipts								
18									
19	Check is received in May of the subsequent year								
20									
21									
22									
23									
24									
25									

ELECTRIC

Acct: **102003009261200**

Unitil Energy Systems, Inc.
Pensions & Benefits Calculation of (Lead) Lag
Dental Insurance
12 Months Ended Dec 31, 2020

Line No	Month	Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days	Weighted Dollar Days
1	January	$ 5,351	1/1/20 12:00 AM	2/1/20 12:00 AM	31	51.30	$ 274,527
2	February	5,351	2/1/20 12:00 AM	3/1/20 12:00 AM	29	51.30	274,527
3	March	3,795	3/1/20 12:00 AM	4/1/20 12:00 AM	31	51.30	194,705
4	April	5,351	4/1/20 12:00 AM	5/1/20 12:00 AM	30	51.30	274,527
5	May	5,351	5/1/20 12:00 AM	6/1/20 12:00 AM	31	51.30	274,527
6	June	(3,053)	6/1/20 12:00 AM	7/1/20 12:00 AM	30	51.30	(156,628)
7	July	5,351	7/1/20 12:00 AM	8/1/20 12:00 AM	31	51.30	274,527
8	August	5,351	8/1/20 12:00 AM	9/1/20 12:00 AM	31	51.30	274,527
9	September	3,563	9/1/20 12:00 AM	10/1/20 12:00 AM	30	51.30	182,764
10	October	5,271	10/1/20 12:00 AM	11/1/20 12:00 AM	31	51.30	270,381
11	November	5,271	11/1/20 12:00 AM	12/1/20 12:00 AM	30	51.30	270,381
12	December	5,351	12/1/20 12:00 AM	1/1/21 12:00 AM	31	51.30	274,527
13							
14		$ 52,306			366	51.30	$ 2,683,295
15							
16							
17	Dental Insurance Expense						
18							
19	Lag Days are from Non ADP Payroll Lead Lag.						
20							
21							
22							
23							
24							
25							

ELECTRIC

Acct: **102003009261201**

Unitil Energy Systems, Inc.
Pensions & Benefits Calculation of (Lead) Lag
Dental Insurance - Emp Contribution
12 Months Ended Dec 31, 2020

Line No	Month	Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days	Weighted Dollar Days
1	January	$ (1,180)	1/1/20 12:00 AM	2/1/20 12:00 AM	31	51.30	$ (60,511)
2	February	(804)	2/1/20 12:00 AM	3/1/20 12:00 AM	29	51.30	(41,237)
3	March	(1,083)	3/1/20 12:00 AM	4/1/20 12:00 AM	31	51.30	(55,539)
4	April	(1,021)	4/1/20 12:00 AM	5/1/20 12:00 AM	30	51.30	(52,394)
5	May	(961)	5/1/20 12:00 AM	6/1/20 12:00 AM	31	51.30	(49,288)
6	June	(1,083)	6/1/20 12:00 AM	7/1/20 12:00 AM	30	51.30	(55,579)
7	July	(996)	7/1/20 12:00 AM	8/1/20 12:00 AM	31	51.30	(51,116)
8	August	(925)	8/1/20 12:00 AM	9/1/20 12:00 AM	31	51.30	(47,469)
9	September	(1,049)	9/1/20 12:00 AM	10/1/20 12:00 AM	30	51.30	(53,797)
10	October	(991)	10/1/20 12:00 AM	11/1/20 12:00 AM	31	51.30	(50,824)
11	November	(944)	11/1/20 12:00 AM	12/1/20 12:00 AM	30	51.30	(48,435)
12	December	(984)	12/1/20 12:00 AM	1/1/21 12:00 AM	31	51.30	(50,493)
13							
14		$ (12,021)			366	51.30	$ (616,683)
15							
16							
17	Employee contributions (through withholdings) for Dental Insurance						
18							
19	Lag Days are from Non ADP Payroll Lead Lag.						
20							
21							
22							
23							
24							
25							

Unitil Energy Systems, Inc.
Pensions & Benefits Calculation of (Lead) Lag
Vision
12 Months Ended Dec 31, 2020

ELECTRIC

Acct: **102003009262400**

Line No	Month	Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days	Weighted Dollar Days
1	January	$ -	1/1/20 12:00 AM	2/1/20 12:00 AM	31	30.00	$ -
2	February	2,376	2/1/20 12:00 AM	3/1/20 12:00 AM	29	30.00	71,269
3	March	866	3/1/20 12:00 AM	4/1/20 12:00 AM	31	30.00	25,987
4	April	-	4/1/20 12:00 AM	5/1/20 12:00 AM	30	30.00	-
5	May	761	5/1/20 12:00 AM	6/1/20 12:00 AM	31	30.00	22,841
6	June	563	6/1/20 12:00 AM	7/1/20 12:00 AM	30	30.00	16,880
7	July	735	7/1/20 12:00 AM	8/1/20 12:00 AM	31	30.00	22,042
8	August	658	8/1/20 12:00 AM	9/1/20 12:00 AM	31	30.00	19,730
9	September	707	9/1/20 12:00 AM	10/1/20 12:00 AM	30	30.00	21,195
10	October	1,552	10/1/20 12:00 AM	11/1/20 12:00 AM	31	30.00	46,557
11	November	257	11/1/20 12:00 AM	12/1/20 12:00 AM	30	30.00	7,703
12	December	564	12/1/20 12:00 AM	1/1/21 12:00 AM	31	30.00	16,930
13							
14		$ 9,038			366	30.00	$ 271,134
15							
16							
17	Vision expense						
18							
19	Lag Days are from Non ADP Payroll Lead Lag.						
20							
21							
22							
23							
24							
25							

ELECTRIC

Acct: **102003009262401**

Unitil Energy Systems, Inc.
Pensions & Benefits Calculation of (Lead) Lag
Vision - EE Contr
12 Months Ended Dec 31, 2020

Line No	Month	Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days	Weighted Dollar Days
1	January	$ (286)	1/1/20 12:00 AM	2/1/20 12:00 AM	31	30.00	$ (8,582)
2	February	(193)	2/1/20 12:00 AM	3/1/20 12:00 AM	29	30.00	(5,778)
3	March	(259)	3/1/20 12:00 AM	4/1/20 12:00 AM	31	30.00	(7,764)
4	April	(244)	4/1/20 12:00 AM	5/1/20 12:00 AM	30	30.00	(7,318)
5	May	(228)	5/1/20 12:00 AM	6/1/20 12:00 AM	31	30.00	(6,837)
6	June	(248)	6/1/20 12:00 AM	7/1/20 12:00 AM	30	30.00	(7,436)
7	July	(250)	7/1/20 12:00 AM	8/1/20 12:00 AM	31	30.00	(7,511)
8	August	(228)	8/1/20 12:00 AM	9/1/20 12:00 AM	31	30.00	(6,832)
9	September	(259)	9/1/20 12:00 AM	10/1/20 12:00 AM	30	30.00	(7,783)
10	October	(242)	10/1/20 12:00 AM	11/1/20 12:00 AM	31	30.00	(7,259)
11	November	(231)	11/1/20 12:00 AM	12/1/20 12:00 AM	30	30.00	(6,931)
12	December	(241)	12/1/20 12:00 AM	1/1/21 12:00 AM	31	30.00	(7,231)
13							
14		$ (2,909)			366	30.00	$ (87,262)
15							
16							
17	Employee Contribution (through withholdings) for Vision coverage						
18							
19	Lag Days are from Non ADP Payroll Lead Lag.						
20							
21							
22							
23							
24							
25							

Unitil Energy Systems, Inc.
Pensions & Benefits Calculation of (Lead) Lag
Empl Benefit - Life Insurance
12 Months Ended Dec 31, 2020

ELECTRIC

Acct: **102003009260400**

Line No	Month	Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days	Weighted Dollar Days
1	January	$ -	-	-	-	7.46	$ -
2	February	1,560	12/1/19 12:00 AM	3/1/20 12:00 AM	91	7.46	11,632
3	March	7,583	1/1/20 12:00 AM	3/1/20 12:00 AM	60	7.46	56,550
4	April	-	-	-	-	7.46	-
5	May	-	-	-	-	7.46	-
6	June	8,145	3/1/20 12:00 AM	6/1/20 12:00 AM	92	7.46	60,736
7	July	-	-	-	-	7.46	-
8	August	-	-	-	-	7.46	-
9	September	-	-	-	-	7.46	-
10	October	3,120	6/1/20 12:00 AM	8/1/20 12:00 AM	61	7.46	23,264
11	November	1,621	9/1/20 12:00 AM	10/1/20 12:00 AM	30	7.46	12,089
12	December	3,222	10/1/20 12:00 AM	12/1/20 12:00 AM	61	7.46	24,027
13							
14		$ 25,251				7.46	$ 188,297
15							
16							
17	Life Insurance benefits						
18							
19	Lag Days are from Non ADP Payroll Lead Lag.						
20							
21							
22							
23							
24							
25							

ELECTRIC

Acct: **102003009261300**

Unitil Energy Systems, Inc.
Pensions & Benefits Calculation of (Lead) Lag
AD&D Insurance
12 Months Ended Dec 31, 2020

Line No	Month	Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days	Weighted Dollar Days
1	January	$ -	-	-	-	7.63	$ -
2	February	178	12/1/19 12:00 AM	1/1/20 12:00 AM	31	7.63	1,361
3	March	-	-	-	-	7.63	-
4	April	-	-	-	-	7.63	-
5	May	-	-	-	-	7.63	-
6	June	11,375	3/1/20 12:00 AM	6/1/20 12:00 AM	92	7.63	86,840
7	July	-	-	-	-	7.63	-
8	August	-	-	-	-	7.63	-
9	September	-	-	-	-	7.63	-
10	October	141	6/1/20 12:00 AM	8/1/20 12:00 AM	61	7.63	1,080
11	November	393	8/1/20 12:00 AM	10/1/20 12:00 AM	61	7.63	3,000
12	December	390	10/1/20 12:00 AM	12/1/20 12:00 AM	61	7.63	2,981
13							
14		$ 12,478				7.63	$ 95,262
15							
16							
17	Payments to LINA (Cigna Group Insurance)						
18							
19	Lag Days are from Non ADP Payroll Lead Lag.						
20							
21							
22							
23							
24							
25							

ELECTRIC

Acct: **102003009261400**

Unitil Energy Systems, Inc.
Pensions & Benefits Calculation of (Lead) Lag
LTD Insurance
12 Months Ended Dec 31, 2020

Line No	Month	Expense Amount	Service From	Service To	Total Days	Mid-Point Calculation Date	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1	January	$ -	-	-	-	-	-	-	$ -
2	February	1,702	12/1/19 12:00 AM	1/1/20 12:00 AM	31	12/16/19 12:00 PM	2/19/20 12:00 AM	64.50	109,767
3	March	6,093	1/1/20 12:00 AM	3/1/20 12:00 AM	60	1/31/20 12:00 AM	3/11/20 12:00 AM	40.00	243,736
4	April	-	-	-	-	-	-	-	-
5	May	-	-	-	-	-	-	-	-
6	June	9,140	3/1/20 12:00 AM	6/1/20 12:00 AM	92	4/16/20 12:00 AM	6/19/20 12:00 AM	64.00	584,966
7	July	-	-	-	-	-	-	-	-
8	August	-	-	-	-	-	-	-	-
9	September	-	-	-	-	-	-	-	-
10	October	4,489	6/1/20 12:00 AM	8/1/20 12:00 AM	61	7/1/20 12:00 PM	10/6/20 12:00 AM	96.50	433,161
11	November	4,866	8/1/20 12:00 AM	10/1/20 12:00 AM	61	8/31/20 12:00 PM	11/2/20 12:00 AM	62.50	304,123
12	December	4,645	10/1/20 12:00 AM	1/1/21 12:00 AM	92	11/16/20 12:00 AM	12/4/20 12:00 AM	18.00	83,606
13									
14		$ 30,935						56.87	$ 1,759,359
15									
16									
17	Payments to LINA (Cigna Group Insurance)								
18									
19									
20									
21									
22									
23									
24									
25									

Unitil Energy Systems, Inc.
Pensions & Benefits Calculation of (Lead) Lag
Employee Benefit Accrual Adj
12 Months Ended Dec 31, 2020

ELECTRIC

Acct: **102010009260302**

Line No	Month	Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days	Weighted Dollar Days
1	January	$ (3,469)	1/1/20 12:00 AM	2/1/20 12:00 AM	31	49.83	$ (172,853.83)
2	February	-	2/1/20 12:00 AM	3/1/20 12:00 AM	29	49.83	-
3	March	-	3/1/20 12:00 AM	4/1/20 12:00 AM	31	49.83	-
4	April	-	4/1/20 12:00 AM	5/1/20 12:00 AM	30	49.83	-
5	May	-	5/1/20 12:00 AM	6/1/20 12:00 AM	31	49.83	-
6	June	-	6/1/20 12:00 AM	7/1/20 12:00 AM	30	49.83	-
7	July	-	7/1/20 12:00 AM	8/1/20 12:00 AM	31	49.83	-
8	August	-	8/1/20 12:00 AM	9/1/20 12:00 AM	31	49.83	-
9	September	-	9/1/20 12:00 AM	10/1/20 12:00 AM	30	49.83	-
10	October	-	10/1/20 12:00 AM	11/1/20 12:00 AM	31	49.83	-
11	November	-	11/1/20 12:00 AM	12/1/20 12:00 AM	30	49.83	-
12	December	11,217	12/1/20 12:00 AM	1/1/21 12:00 AM	31	49.83	558,949.73
13							
14		$ 7,748			366	49.83	$ 386,096
15							
16							
17	Represents the additional benefits items capitalized but not yet classified by Plant Accounting						
18							
19	Lag based on Total Direct Benefits used for Capitalized Items Lead Lag from Summary Schedule						
20							
21							
22							
23							
24							
25							

Unitil Energy Systems, Inc.
Pensions & Benefits Calculation of (Lead) Lag
Benefit Cost Capitalized
12 Months Ended Dec 31, 2020

ELECTRIC

Acct: **102010009260500**

Line No	Month	Expense Amount	Service From	Service To	Total Days	(Lead) Lag Days	Weighted Dollar Days
1	January	$ (78,351)	1/1/20 12:00 AM	2/1/20 12:00 AM	31	49.83	$ (3,904,395)
2	February	(63,581)	2/1/20 12:00 AM	3/1/20 12:00 AM	29	49.83	(3,168,337)
3	March	(77,825)	3/1/20 12:00 AM	4/1/20 12:00 AM	31	49.83	(3,878,152)
4	April	(110,461)	4/1/20 12:00 AM	5/1/20 12:00 AM	30	49.83	(5,504,484)
5	May	(60,756)	5/1/20 12:00 AM	6/1/20 12:00 AM	31	49.83	(3,027,582)
6	June	74,099	6/1/20 12:00 AM	7/1/20 12:00 AM	30	49.83	3,692,469
7	July	(43,977)	7/1/20 12:00 AM	8/1/20 12:00 AM	31	49.83	(2,191,471)
8	August	(59,843)	8/1/20 12:00 AM	9/1/20 12:00 AM	31	49.83	(2,982,087)
9	September	(30,735)	9/1/20 12:00 AM	10/1/20 12:00 AM	30	49.83	(1,531,589)
10	October	(70,126)	10/1/20 12:00 AM	11/1/20 12:00 AM	31	49.83	(3,494,520)
11	November	(46,674)	11/1/20 12:00 AM	12/1/20 12:00 AM	30	49.83	(2,325,839)
12	December	(60,525)	12/1/20 12:00 AM	1/1/21 12:00 AM	31	49.83	(3,016,075)
13							
14		$ (628,755)			366	49.83	$ (31,332,061)
15							
16							
17	Employee Benefit expense offset for capitalization						
18							
19	Lag based on Total Direct Benefits used for Capitalized Items Lead Lag from Summary Schedule						
20							
21							
22							
23							
24							
25							

Unitil Energy Systems, Inc.
Pensions & Benefits Calculation of (Lead) Lag
Empl Benefits Other
12 Months Ended Dec 31, 2020

ELECTRIC

Acct: **102003009260600**

Line No	Month	Expense Amount	Service From	Service To	Total Days	Mid-Point Calculation Date	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1	January	$ 7,144	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/15/20 12:00 PM	54.93	$ 392,407
2	February	1,737	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/15/20 12:00 PM	54.93	95,397
3	March	(245)	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/15/20 12:00 AM	54.93	(13,448)
4	April	2,822	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/15/20 12:00 AM	54.93	155,029
5	May	60	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/15/20 12:00 AM	54.93	3,319
6	June	(418)	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/15/20 12:00 AM	54.93	(22,962)
7	July	923	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/15/20 12:00 AM	54.93	50,708
8	August	1,235	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/15/20 12:00 AM	54.93	67,824
9	September	2,184	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/15/20 12:00 AM	54.93	119,953
10	October	(604)	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/15/20 12:00 AM	54.93	(33,180)
11	November	10,293	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/15/20 12:00 AM	54.93	565,390
12	December	(3,540)	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	1/15/20 12:00 AM	54.93	(194,434)
13									
14		$ 21,591			366			54.93	$ 1,186,002
15									
16									
17	Misc Employee Benefit expenses representing a number of unrelated expenses (e.g., safety shoes, doctor referrals, kitchen supplies, physicals, drug screening, flu shots)								
18									
19	Use lag for Other O&M expenses								
20									
21									
22									
23									
24									
25									

Calculation Acct 925 Injuries & Damages Lead Lag Days
12 Months Ended December 31, 2020

Line No	Annual Charges to Acct	Total 2020 Charges	Lag Days	Weighted Dollar Days
1				
2				
3	10-20-08-00-9250000 D & O AND FIDUCIARY	$ 57,707	(166.50)	$ (9,608,162)
4	10-20-08-00-9250200 GENERAL LIABILITY	410,185	(156.57)	$ (64,220,757)
5	10-20-08-00-9250400 WORKERS COMP EX	84,702	(39.90)	$ (3,379,208)
6	10-20-10-00-9250201 GENERAL LIABILITY CAPITILIZED	(285,588)	(156.57)	$ 44,713,167
7	10-20-10-00-9250401 WORKMEN'S COMP CAPITILIZED	(46,133)	(39.90)	$ 1,840,501
8				
9	Total Injuries & Damages Acct 925	$ 220,873	(138.79)	$ (30,654,459)
10				
11				
12	10-20-08-00-9240000 PROPERTY INSURANCE	82,353	(137.50)	(11,323,553)
13	10-20-10-00-9240001 PROPERTY INS CAPITALIZED	(8,592)	(137.50)	1,181,400
14				
15	Total Property Insurance Acct 924	$ 73,761	(137.50)	$ (10,142,153)
16				
17				
18				
19	Total Damanges and Property Insurance	$ 294,634	$ (138.47)	$ (40,796,611)
20				

Unitil Energy Systems, Inc.
Calculation Acct 925 Injuries & Damages Lead Lag Days
12 Months Ended December 31, 2020
D & O Fiduciary

Expense Initially Charged to
Acct 10-20-00-00-1650101 - Prepaid Inj & Dam Ins

Line No	Charges for Expense Account	2020 Payment Amounts	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Date Paid	Lag Days	Weighted Dollar Days
1									
2	10-20-08-00-9250000 D & O AND FIDUCIARY								
3									
4	LOCKTON COMPANIES	$ 57,707	4/28/20 12:00 AM	4/28/21 12:00 AM	365	10/27/20 12:00 PM	5/14/20 12:00 AM	(166.50)	$ (9,608,162)
5									
6	Total 2020 Payments - D&O & FIDUCIARY	$ 57,707						(166.50)	$ (9,608,162)
7									
8									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									

Unitil Energy Systems, Inc.
Calculation Acct 925 Injuries & Damages Lead Lag Days
12 Months Ended December 31, 2020
General Liability

Expense Initially Charged to:
Acct 10-20-00-00-1650101 - Prepaid Inj & Dam Ins

Line No	Charges for Expense Account	2020 Payment Amounts	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Date Paid	Lag Days	Weighted Dollar Days
1									
2	10-20-08-00-9250200 GENERAL LIABILITY								
3									
4	LOCKTON COMPANIES	$ 16,498	1/1/21 12:00 AM	12/31/21 12:00 AM	364	7/2/21 12:00 AM	12/28/20 12:00 AM	(186.00)	$ (3,068,652)
5	LOCKTON COMPANIES (HUB Cyber)	12,963	9/1/20 12:00 AM	9/1/21 12:00 AM	365	3/2/21 12:00 PM	9/11/20 12:00 AM	(172.50)	(2,236,085)
6	LOCKTON COMPANIES (HUB Cyber)	8,956	9/1/20 12:00 AM	9/1/21 12:00 AM	365	3/2/21 12:00 PM	10/30/20 12:00 AM	(123.50)	(1,106,082)
7	LOCKTON COMPANIES (Excess Liability)	371,768	1/1/20 12:00 AM	12/31/20 12:00 AM	365	7/1/20 12:00 PM	1/28/20 12:00 AM	(155.50)	(57,809,938)
8									
9	Total 2020 Payments - GENERAL LIABILITY	$ 410,185						(156.57)	$ (64,220,757)
10									
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									

Unitil Energy Systems, Inc.
Calculation Acct 925 Injuries & Damages Lead Lag Days
12 Months Ended December 31, 2020
Workmen's Compensation

Line No	Charges for Expense Account	2020 Payment Amounts	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Date Paid	Lag Days	Weighted Dollar Days
1									
2	10-20-08-00-9250400 WORKERS COMPENSATION EXP								
3									
4	Current Policy Payments	$ 15,343	10/1/19 12:00 AM	10/1/20 12:00 AM	366	4/1/20 12:00 AM	11/8/19 12:00 AM	(145.00)	$ (2,224,767)
5		7,672	10/1/19 12:00 AM	10/1/20 12:00 AM	366	4/1/20 12:00 AM	12/10/19 12:00 AM	(113.00)	(866,893)
6		7,986	10/1/19 12:00 AM	10/1/20 12:00 AM	366	4/1/20 12:00 AM	1/7/20 12:00 AM	(85.00)	(678,801)
7		7,672	10/1/19 12:00 AM	10/1/20 12:00 AM	366	4/1/20 12:00 AM	1/7/20 12:00 AM	(85.00)	(652,088)
8		7,672	10/1/19 12:00 AM	10/1/20 12:00 AM	366	4/1/20 12:00 AM	2/12/20 12:00 AM	(49.00)	(375,909)
9		7,672	10/1/19 12:00 AM	10/1/20 12:00 AM	366	4/1/20 12:00 AM	3/11/20 12:00 AM	(21.00)	(161,104)
10		7,672	10/1/19 12:00 AM	10/1/20 12:00 AM	366	4/1/20 12:00 AM	4/8/20 12:00 AM	7.00	53,701
11		7,672	10/1/19 12:00 AM	10/1/20 12:00 AM	366	4/1/20 12:00 AM	5/7/20 12:00 AM	36.00	276,178
12		7,672	10/1/19 12:00 AM	10/1/20 12:00 AM	366	4/1/20 12:00 AM	6/5/20 12:00 AM	65.00	498,655
13		7,672	10/1/19 12:00 AM	10/1/20 12:00 AM	366	4/1/20 12:00 AM	7/8/20 12:00 AM	98.00	751,819
14									
15	Total 2020 Payments - Workmen's Compensation	$ 84,702						(39.90)	$ (3,379,208)
16									
17									
18									
19									
20									

Unitil Energy Systems, Inc.
Calculation Acct 925 Injuries & Damages Lead Lag Days
12 Months Ended December 31, 2020
PROPERTY INSURANCE

Expense Initially Charged to:
Acct 10-20-00-00-1650100 - PREPAID PROPERTY INSURANCE

Line No	Charges for Expense Account	2020 Payment Amounts	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Date Paid	Lag Days	Weighted Dollar Days
1									
2	10-20-08-00-9240000 PROPERTY INSURANCE								
3									
4	LOCKTON COMPANIES	$ 82,353	5/1/20 12:00 AM	5/1/21 12:00 AM	365	10/30/20 12:00 PM	6/15/20 12:00 AM	(137.50)	$ (11,323,553)
5									
6	Total 2020 Payments - PROPERTY INSURANCE	$ 82,353						(137.50)	$ (11,323,553)
7									
8									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									

Unitil Energy Systems, Inc.
Calculation of Acct 928 Regulatory Commission Expense Lead Lag Days
12 Months Ended December 31, 2020
Regulatory Commission Assesment Fees

Acct. #10-20-01-00-9280100

Line No	Description of Payment		Expense Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Scheduled Payment Date	(Lead) Lag Days		Weighted Dollar Days
1	NH Public Utilities Commission	$	195,528	7/1/19 12:00 AM	7/1/20 12:00 AM	366	12/31/19 12:00 AM	2/6/20 12:00 AM	37.00	$	7,234,536
2	NH Public Utilities Commission		195,528	7/1/19 12:00 AM	7/1/20 12:00 AM	366	12/31/19 12:00 AM	5/7/20 12:00 AM	128.00		25,027,584
3	NH Public Utilities Commission		164,022	7/1/20 12:00 AM	7/1/21 12:00 AM	365	12/30/20 12:00 PM	9/24/20 12:00 AM	(97.50)		(15,992,145)
4	NH Public Utilities Commission		200,471	7/1/20 12:00 AM	7/1/21 12:00 AM	365	12/30/20 12:00 PM	10/22/20 12:00 AM	(69.50)		(13,932,735)
5											
6	Total Public Utility Assessment	$	755,549						3.09	$	2,337,241
7											
8											
9											
10											

Unitil Energy Systems, Inc.
Other O&M Expense
Vouchers - All Other

Strata	Sample Population ($)	Sample Population (#)	Sample ($)	Sample (#)	Sample Weighted Dollars	Population Adjusted Weighted Dollars	Lag Days
Stratum 1 - Vouchers greater than $20,000 / every 3rd	$ 3,294,214	45	$ 1,269,716	15	$ 53,227,736	$ 138,096,715	41.92
Stratum 2 - Every 25th voucher from $20,000 down to $1,500	2,776,573	638	112,475	25	7,332,472	181,009,862	65.19
Stratum 3 - Every 150th voucher under $1,500	894,924	2,477	6,776	17	481,056	63,529,911	70.99
	$ 6,965,711	3,160	$ 1,388,967	57	$ 61,041,264	$ 382,636,488	54.93

Unitil Energy Systems, Inc.
Other O&M Expense
Vouchers - All Other - Invoice Selection

VEND_CODE	VOUCHER_NO	Co	Div	Dept	RM	FERC	SUB1/2	JNL_AMT	PAY_DATE	SVC_START_DATE	SVC_END_DATE	SERVICE DAYS LAG	Service Period Midpoint	Lag Days	Weighted Dollars Days	Sample #
NORTHERN TREE	785975	10	20	28	00	593	0418	364,100.00	2020-03-19	2/8/2020	2/15/2020	7.00	2/11/2020	37	$ 13,289,650	1
ASPLUNDH TRE PA	791830	10	20	28	00	593	0418	203,795.48	2020-05-07	4/4/2020	4/11/2020	7.00	4/7/2020	30	$ 6,011,967	2
ASPLUNDH TRE PA	782980	10	20	28	00	593	0410	122,169.15	2020-02-10	11/30/2019	12/7/2019	7.00	12/3/2019	69	$ 8,368,587	3
ASPLUNDH TRE PA	793227	10	20	28	00	593	0416	109,590.88	2020-05-18	4/11/2020	4/18/2020	7.00	4/14/2020	34	$ 3,671,294	4
LUCAS TREE	809202	10	20	28	00	593	0410	79,295.50	2020-10-21	9/12/2020	9/19/2020	7.00	9/15/2020	36	$ 2,814,990	5
NORTHERN TREE	785686	10	20	28	00	593	0418	73,450.00	2020-03-12	2/15/2020	2/22/2020	7.00	2/18/2020	23	$ 1,652,625	6
ASPLUNDH TRE PA	819967	10	20	28	00	593	0418	59,860.00	2020-12-23	11/21/2020	11/28/2020	7.00	11/24/2020	29	$ 1,706,010	7
LUCAS TREE	780951	10	20	28	00	593	0410	51,465.00	2020-01-21	11/2/2019	11/9/2019	7.00	11/5/2019	77	$ 3,937,073	8
LUCAS TREE	808540	10	20	28	00	593	0416	48,616.50	2020-10-07	8/22/2020	8/29/2020	7.00	8/25/2020	43	$ 2,066,201	9
ASPLUNDH TRE PA	808385	10	20	28	00	593	0410	33,850.00	2020-10-14	9/5/2020	9/12/2020	7.00	9/8/2020	36	$ 1,201,675	10
LUCAS TREE	808534	10	20	28	00	593	0416	29,169.90	2020-09-24	7/25/2020	8/1/2020	7.00	7/28/2020	58	$ 1,677,269	11
ASPLUNDH TRE PA	802135	10	20	28	00	593	0415	26,022.68	2020-08-03	4/12/2020	5/1/2020	19.00	4/21/2020	104	$ 2,693,347	12
ASPLUNDH TRE PA	793416	10	20	28	00	593	0418	24,081.22	2020-05-27	12/23/2019	3/13/2020	81.00	2/1/2020	116	$ 2,781,381	13
KUBRA DATA	786182	10	20	21	00	903	0400	22,559.26	2020-03-11	2/1/2020	2/29/2020	28.00	2/15/2020	25	$ 563,982	14
LUCAS TREE	799105	10	20	28	00	593	0410	21,690.00	2020-07-16	6/6/2020	6/13/2020	7.00	6/9/2020	37	$ 791,685	15
ASPLUNDH TRE PA	790936	10	20	28	00	593	0415	19,984.89	2020-04-27	1/25/2020	3/21/2020	56.00	2/22/2020	65	$ 1,299,018	16
ASPLUNDH TRE PA	802132	10	20	28	00	593	0415	13,125.88	2020-08-03	1/2/2020	3/26/2020	84.00	2/13/2020	172	$ 2,257,651	17
LUCAS TREE	813385	10	20	28	00	593	0417	10,100.00	2020-11-02	9/14/2020	9/19/2020	5.00	9/16/2020	47	$ 469,650	18
ASPLUNDH TRE PA	789360	10	20	28	00	593	0411	7,272.65	2020-04-20	3/14/2020	3/21/2020	7.00	3/17/2020	34	$ 243,634	19
ASPLUNDH TRE PA	805260	10	20	28	00	593	0418	6,274.64	2020-08-31	7/25/2020	8/1/2020	7.00	7/28/2020	34	$ 210,200	20
ASPLUNDH TRE PA	810554	10	20	28	00	593	0415	5,640.08	2020-10-07	4/28/2020	7/16/2020	79.00	6/6/2020	123	$ 690,910	21
ASPLUNDH TRE PA	789369	10	20	28	00	593	0411	5,183.59	2020-04-27	3/21/2020	3/28/2020	7.00	3/24/2020	34	$ 173,650	22
ASPLUNDH TRE PA	818807	10	20	28	00	593	0411	4,662.49	2020-12-16	11/14/2020	11/21/2020	7.00	11/17/2020	29	$ 132,881	23
ASPLUNDH TRE PA	800994	10	20	28	00	593	0418	4,248.00	2020-07-24	6/13/2020	6/20/2020	7.00	6/16/2020	38	$ 159,300	24
ASPLUNDH TRE PA	786812	10	20	28	00	593	0418	3,898.42	2020-03-16	12/13/2019	12/18/2019	5.00	12/15/2019	92	$ 356,705	25
I C REED & SONS	804828	10	20	60	00	593	0100	3,312.32	2020-08-31	7/31/2020	8/7/2020	7.00	8/3/2020	28	$ 91,089	26
ASPLUNDH TRE PA	794563	10	20	28	00	593	0413	2,927.61	2020-06-08	5/2/2020	5/9/2020	7.00	5/5/2020	34	$ 98,075	27
I C REED & SONS	818349	10	20	60	00	593	0100	2,658.02	2020-12-09	11/5/2020	11/6/2020	1.00	11/5/2020	34	$ 89,044	28
HI VOLT LINE	785060	10	20	50	00	593	0100	2,564.86	2020-03-02	2/1/2020	2/8/2020	7.00	2/4/2020	27	$ 67,969	29
ASPLUNDH TRE PA	785591	10	20	28	00	593	0416	2,395.80	2020-03-04	1/18/2020	1/25/2020	7.00	1/21/2020	43	$ 101,822	30
HI VOLT LINE	789069	10	20	50	00	593	0100	2,187.82	2020-04-20	3/21/2020	3/28/2020	7.00	3/24/2020	27	$ 57,977	31
ACRT INC	801056	10	20	28	00	593	0418	2,051.36	2020-07-24	2/1/2020	2/2/2020	1.00	2/1/2020	174	$ 355,911	32
ASPLUNDH TRE PA	785610	10	20	28	00	593	0422	1,974.96	2020-03-04	1/11/2020	1/18/2020	7.00	1/14/2020	50	$ 97,761	33
ACRT INC	819427	10	20	28	00	593	0418	1,904.00	2020-12-23	11/14/2020	11/21/2020	7.00	11/17/2020	36	$ 67,592	34
LUCAS TREE	785980	10	20	28	00	593	0415	1,855.35	2020-03-09	1/25/2020	2/1/2020	7.00	1/28/2020	41	$ 75,142	35
HI VOLT LINE	804584	10	20	50	00	593	0100	1,801.73	2020-08-24	7/25/2020	8/1/2020	7.00	7/28/2020	27	$ 47,746	36
ASPLUNDH TRE PA	787231	10	20	28	00	593	0421	1,719.21	2020-03-30	2/22/2020	2/29/2020	7.00	2/25/2020	34	$ 57,594	37
ASPLUNDH TRE PA	793224	10	20	60	00	593	0100	1,620.42	2020-05-18	4/11/2020	4/18/2020	7.00	4/14/2020	34	$ 54,284	38
A1 PHOENIX CLN	811885	10	20	50	00	588	1200	1,569.75	2020-11-05	10/1/2020	10/31/2020	30.00	10/16/2020	20	$ 31,395	39
ASPLUNDH TRE PA	812520	10	20	28	00	593	0415	1,541.48	2020-10-29	9/26/2020	10/3/2020	7.00	9/29/2020	30	$ 45,474	40
ATC GROUP	797327	10	20	60	00	935	0102	1,495.25	2020-06-22	10/18/2019	3/10/2020	144.00	12/29/2019	176	$ 263,164	41
LUCAS TREE	812296	10	20	28	00	593	0415	1,194.11	2020-10-26	9/1/2020	9/3/2020	2.00	9/2/2020	54	$ 64,482	42
ASPLUNDH TRE PA	780300	10	20	28	00	593	0420	924.98	2020-01-15	12/7/2019	12/14/2019	7.00	12/10/2019	36	$ 32,837	43
DIG SAFE SYSTEM	782764	10	20	60	00	584	0200	739.11	2020-02-10	2/1/2020	2/29/2020	28.00	2/15/2020	(5)	$ (3,696)	44
CONSOLID COMM	817790	10	20	28	00	581	0000	587.00	2020-12-15	10/21/2020	11/20/2020	30.00	11/5/2020	40	$ 23,480	45
BLACKBURN MFG	796646	10	20	50	00	584	0100	456.00	2020-07-06	6/10/2020	6/11/2020	1.00	6/10/2020	26	$ 11,628	46
ASPLUNDH TRE PA	785619	10	20	28	00	593	0415	336.00	2020-03-04	8/20/2019	8/21/2019	1.00	8/20/2019	197	$ 66,024	47
SPOK INC	784138	10	20	50	00	921	1800	268.49	2020-02-19	1/31/2020	2/29/2020	29.00	2/14/2020	5	$ 1,208	48
NEW ENGLAND TRA	788550	10	20	50	00	583	0200	210.00	2020-04-09	3/9/2020	3/13/2020	4.00	3/11/2020	29	$ 6,090	49
PLAISTOW POLICE	807646	10	20	60	00	583	0200	156.00	2020-09-17	8/31/2020	9/2/2020	2.00	9/1/2020	16	$ 2,496	50
STEVENS BUSINES	780851	10	20	21	00	903	0503	112.72	2020-01-27	12/1/2019	12/31/2019	30.00	12/16/2019	42	$ 4,734	51
CONSOLID COMM	795147	10	20	28	00	581	0000	92.02	2020-06-08	4/18/2020	5/17/2020	29.00	5/2/2020	37	$ 3,359	52
WB MASON CO	794950	10	20	60	00	926	0600	74.49	2020-06-15	5/20/2020	5/21/2020	1.00	5/20/2020	26	$ 1,899	53
TDS TELECOM	798824	10	20	28	00	581	0000	48.73	2020-07-09	6/1/2020	6/30/2020	29.00	6/15/2020	24	$ 1,145	54
WB MASON CO	814195	10	20	60	00	588	1200	39.99	2020-11-05	10/15/2020	10/16/2020	1.00	10/15/2020	21	$ 820	55
CRYSTAL ROCK	802221	10	20	50	00	588	1200	27.99	2020-08-03	6/23/2020	6/24/2020	1.00	6/23/2020	41	$ 1,134	56
STAPLES BUSINES	782762	10	20	60	00	588	0100	13.59	2020-02-10	1/22/2020	1/23/2020	1.00	1/22/2020	19	$ 251	57

Unitil Energy Systems, Inc.
Calculation of Service Company Charges Lead Lag Days
12 Months Ended Dec 31, 2020
Summary of Service Company Charges

Line No	Annual Charges	Total Payments	Lag Days	Weighted Dollar Days
1				
2				
3	Total Electric Base	$ 10,304,593	36.44	$ 375,502,790
4				
5	Total Elect Flow Thru	1,049,136	36.38	38,172,285
6				
7	Total Service Company Charges	$ 11,353,730	36.44	$ 413,675,076
8				
9				
10				
11				
12				
13				
14				
15				

Unitil Energy Systems, Inc.
Calculation of Service Company Charges Lead Lag Days
12 Months Ended Dec 31, 2020
January Charges

Line No	Charges	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Date Paid	Lag Days	Weighted Dollar Days
1									
2	Total Electric Base	$ 934,014	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/24/20 12:00 PM	39.00	$ 36,426,534
3	Total Elect Flow Thru	82,205	1/1/20 12:00 AM	2/1/20 12:00 AM	31	1/16/20 12:00 PM	2/24/20 12:00 PM	39.00	3,205,999
4									
5	Total Months Charges	$ 1,016,219						39.00	$ 39,632,532
6						Cash Pool Date	2/24/2020		
7									
8									
9									
10									
11									
12									
13									
14									
15									

Unitil Energy Systems, Inc.
Calculation of Service Company Charges Lead Lag Days
12 Months Ended Dec 31, 2020
February Charges

Line No	Charges	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Date Paid	Lag Days	Weighted Dollar Days
1									
2	Total Electric Base	$ 960,455	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/26/20 12:00 PM	40.00	$ 38,418,213
3	Total Elect Flow Thru	97,805	2/1/20 12:00 AM	3/1/20 12:00 AM	29	2/15/20 12:00 PM	3/26/20 12:00 PM	40.00	3,912,194
4									
5	Total Months Charges	$ 1,058,260						40.00	$ 42,330,407
6						Cash Pool Date	3/26/2020		
7									
8									
9									
10									
11									
12									
13									
14									
15									

Unitil Energy Systems, Inc.
Calculation of Service Company Charges Lead Lag Days
12 Months Ended Dec 31, 2020
March Charges

Line No	Charges	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Date Paid	Lag Days	Weighted Dollar Days
1									
2	Total Electric Base	$ 1,094,974	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/23/20 12:00 PM	38.00	$ 41,609,009
3	Total Elect Flow Thru	119,736	3/1/20 12:00 AM	4/1/20 12:00 AM	31	3/16/20 12:00 PM	4/23/20 12:00 PM	38.00	4,549,963
4									
5	Total Months Charges	$ 1,214,710						38.00	$ 46,158,971
6						Cash Pool Date	4/23/2020		
7									
8									
9									
10									
11									
12									
13									
14									
15									

Unitil Energy Systems, Inc.
Calculation of Service Company Charges Lead Lag Days
12 Months Ended Dec 31, 2020
April Charges

Line No	Charges	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Date Paid	Lag Days	Weighted Dollar Days
1									
2	Total Electric Base	$ 834,692	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/21/20 12:00 PM	35.50	$ 29,631,581
3	Total Elect Flow Thru	83,605	4/1/20 12:00 AM	5/1/20 12:00 AM	30	4/16/20 12:00 AM	5/21/20 12:00 PM	35.50	2,967,979
4									
5	Total Months Charges	$ 918,297						35.50	$ 32,599,561
6						Cash Pool Date	5/21/2020		
7									
8									
9									
10									
11									
12									
13									
14									
15									

Unitil Energy Systems, Inc.
Calculation of Service Company Charges Lead Lag Days
12 Months Ended Dec 31, 2020
May Charges

Line No	Charges	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Date Paid	Lag Days	Weighted Dollar Days
1									
2	Total Electric Base	$ 830,554	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/25/20 12:00 PM	40.00	$ 33,222,148
3	Total Elect Flow Thru	86,518	5/1/20 12:00 AM	6/1/20 12:00 AM	31	5/16/20 12:00 PM	6/25/20 12:00 PM	40.00	3,460,700
4									
5	Total Months Charges	$ 917,071						40.00	$ 36,682,848
6						Cash Pool Date	6/25/2020		
7									
8									
9									
10									
11									
12									
13									
14									
15									

Unitil Energy Systems, Inc.
Calculation of Service Company Charges Lead Lag Days
12 Months Ended Dec 31, 2020
June Charges

Line No	Charges	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Date Paid	Lag Days	Weighted Dollar Days
1									
2	Total Electric Base	$ 716,588	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/16/20 12:00 PM	30.50	$ 21,855,928
3	Total Elect Flow Thru	78,774	6/1/20 12:00 AM	7/1/20 12:00 AM	30	6/16/20 12:00 AM	7/16/20 12:00 PM	30.50	2,402,602
4									
5	Total Months Charges	$ 795,362						30.50	$ 24,258,529
6						Cash Pool Date	7/16/2020		
7									
8									
9									
10									
11									
12									
13									
14									
15									

Unitil Energy Systems, Inc.
Calculation of Service Company Charges Lead Lag Days
12 Months Ended Dec 31, 2020
July Charges

Line No	Charges	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Date Paid	Lag Days	Weighted Dollar Days
1									
2	Total Electric Base	$ 812,280	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/21/20 12:00 PM	36.00	$ 29,242,084
3	Total Elect Flow Thru	83,718	7/1/20 12:00 AM	8/1/20 12:00 AM	31	7/16/20 12:00 PM	8/21/20 12:00 PM	36.00	3,013,854
4									
5	Total Months Charges	$ 895,998						36.00	$ 32,255,938
6						Cash Pool Date	8/21/2020		
7									
8									
9									
10									
11									
12									
13									
14									
15									

Unitil Energy Systems, Inc.
Calculation of Service Company Charges Lead Lag Days
12 Months Ended Dec 31, 2020
August Charges

Line No	Charges	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Date Paid	Lag Days	Weighted Dollar Days
1									
2	Total Electric Base	$ 789,031	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/24/20 12:00 PM	39.00	$ 30,772,197
3	Total Elect Flow Thru	77,457	8/1/20 12:00 AM	9/1/20 12:00 AM	31	8/16/20 12:00 PM	9/24/20 12:00 PM	39.00	3,020,828
4									
5	Total Months Charges	$ 866,488						39.00	$ 33,793,025
6						Cash Pool Date	9/24/2020		
7									
8									
9									
10									
11									
12									
13									
14									
15									

Unitil Energy Systems, Inc.
Calculation of Service Company Charges Lead Lag Days
12 Months Ended Dec 31, 2020
September Charges

Line No	Charges	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Date Paid	Lag Days	Weighted Dollar Days
1									
2	Total Electric Base	$ 786,037	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/21/20 12:00 PM	35.50	$ 27,904,307
3	Total Elect Flow Thru	74,707	9/1/20 12:00 AM	10/1/20 12:00 AM	30	9/16/20 12:00 AM	10/21/20 12:00 PM	35.50	2,652,095
4									
5	Total Months Charges	$ 860,744						35.50	$ 30,556,402
6						Cash Pool Date	10/21/2020		
7									
8									
9									
10									
11									
12									
13									
14									
15									

Unitil Energy Systems, Inc.
Calculation of Service Company Charges Lead Lag Days
12 Months Ended Dec 31, 2020
October Charges

Line No	Charges	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Date Paid	Lag Days	Weighted Dollar Days
1									
2	Total Electric Base	$ 847,164	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/19/20 12:00 PM	34.00	$ 28,803,573
3	Total Elect Flow Thru	81,192	10/1/20 12:00 AM	11/1/20 12:00 AM	31	10/16/20 12:00 PM	11/19/20 12:00 PM	34.00	2,760,526
4									
5	Total Months Charges	$ 928,356						34.00	$ 31,564,098
6						Cash Pool Date	11/19/2020		
7									
8									
9									
10									
11									
12									
13									
14									
15									

Unitil Energy Systems, Inc.
Calculation of Service Company Charges Lead Lag Days
12 Months Ended Dec 31, 2020
November Charges

Line No	Charges	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Date Paid	Lag Days	Weighted Dollar Days
1									
2	Total Electric Base	$ 786,614	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/17/20 12:00 PM	31.50	$ 24,778,350
3	Total Elect Flow Thru	83,906	11/1/20 12:00 AM	12/1/20 12:00 AM	30	11/16/20 12:00 AM	12/17/20 12:00 PM	31.50	2,643,041
4									
5	Total Months Charges	$ 870,520						31.50	$ 27,421,391
6						Cash Pool Date	12/17/2020		
7									
8									
9									
10									
11									
12									
13									
14									
15									

Unitil Energy Systems, Inc.
Calculation of Service Company Charges Lead Lag Days
12 Months Ended Dec 31, 2020
December Charges

Line No	Charges	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Date Paid	Lag Days	Weighted Dollar Days
1									
2	Total Electric Base	$ 912,191	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	1/21/21 12:00 PM	36.00	$ 32,838,867
3	Total Elect Flow Thru	99,514	12/1/20 12:00 AM	1/1/21 12:00 AM	31	12/16/20 12:00 PM	1/21/21 12:00 PM	36.00	3,582,506
4									
5	Total Months Charges	$ 1,011,705						36.00	$ 36,421,373
6						Cash Pool Date	1/21/2021		
7									
8									
9									
10									
11									
12									
13									
14									
15									

Unitil Energy Systems, Inc.
Calculation of Taxes Other Than Income Lead Lag Days
12 Months Ended December 31, 2020
Summary of Taxes Other Than Income Excluding Property Taxes

Line No	Type of Tax	Test Period Expense	(Lead) Lag Days	Test Period Weighted Dollar Days
1				
2	Taxes FICA Employer	$ 449,302	11.60	$ 5,211,347
3	Federal Unemployment Tax	1,863	8.04	14,974
4	NH Unemployment Tax	963	22.01	21,202
5	NH Surplus Tax	12,845	(157.12)	(2,018,210)
6	NH BET Tax Expense - Current	78,000	37.50	2,925,000
7	Payroll Taxes Capitalized	(271,803)	11.61	(3,154,617)
8				
9	Total Taxes Excluding Property Taxes	$ 271,171	11.06	$ 2,999,697
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				

Unitil Energy Systems, Inc.
Calculation of NH Surplus Tax
12 Months Ended December 31, 2020

G/L #10-20-10-00-408-02-10

Line No	Payroll Description	Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Payment Date	(Lead) Lag Days	Weighted Dollar Days
1	**Weekly**								
2									
3	January	$ 10,602	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	1/28/20 12:00 AM	(156.00)	$ (1,653,854)
4	February	-	-	-	-	1/0/00 12:00 AM	-	-	-
5	March	-	-	-	-	1/0/00 12:00 AM	-	-	-
6	April	-	-	-	-	1/0/00 12:00 AM	-	-	-
7	May	1,586	4/28/20 12:00 AM	4/28/21 12:00 AM	365	10/27/20 12:00 PM	5/14/20 12:00 AM	(166.50)	(264,092)
8	June	-	-	-	-	1/0/00 12:00 AM	-	-	-
9	July	-	-	-	-	1/0/00 12:00 AM	-	-	-
10	August	-	-	-	-	1/0/00 12:00 AM	-	-	-
11	September	389	9/1/20 12:00 AM	9/1/21 12:00 AM	365	3/2/21 12:00 PM	9/11/20 12:00 AM	(172.50)	(67,082)
12	October	269	9/1/20 12:00 AM	9/1/21 12:00 AM	365	3/2/21 12:00 PM	10/30/20 12:00 AM	(123.50)	(33,182)
13	November	-	-	-	-	1/0/00 12:00 AM	-	-	-
14	December	-	-	-	-	1/0/00 12:00 AM	-	-	-
15									
16		$ 12,845						(157.12)	$ (2,018,210)
17									
18									
19									
20									
21									
22									
23									
24									
25									

Unitil Energy Systems, Inc.
Calculation of Property Taxes Lead Lag Days
12 Months Ended December 31, 2020
Summary of Property Taxes

Line No	Type of Tax	Test Period Charges	(Lead) Lag Days	Weighted Dollar Days
1	January 2020 Payments	$ -	-	$ -
2	February 2020 Payments	-	-	-
3	March 2020 Payments	450,514	78.00	35,140,123
4	April 2020 Payments	396,927	(177.50)	(70,454,543)
5	May 2020 Payments	-	-	-
6	June 2020 Payments	2,234,004	(120.89)	(270,062,260)
7	July 2020 Payments	322,384	(57.16)	(18,426,909)
8	August 2020 Payments	-	-	-
9	September 2020 Payments	837,573	(59.38)	(49,734,343)
10	October 2020 Payments	-	-	-
11	November 2020 Payments	282,134	101.69	28,688,912
12	December 2020 Payments	2,542,901	62.96	160,105,645
13				
14	Total Payments	$ 7,066,437	(26.14)	$ (184,743,374)
15				
16				
17				
18				
19				
20				

Unitil Energy Systems, Inc.
Calculation of Property Taxes Lead Lag Days
12 Months Ended December 31, 2020
March 2020 Payments

Line No	Description of Payment	Payment Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Check Date	(Lead) Lag Days	Weighted Dollar Days
1	CITY OF CONCORD NH	$ 450,514	7/1/19 12:00 AM	7/1/20 12:00 AM	366	12/31/19 12:00 AM	3/18/20 12:00 AM	78.00	$ 35,140,123.20
2									
3									
4		$ 450,514							$ 35,140,123
5									
6									
7		Total March 2020 Payments				$ 450,514			
8									
9		Total Weighted Dollar Days				$ 35,140,123			
10									
11		March 2020 Payments (Lead) Lag Days				78.00			
12									
13									
14									
15									

Unitil Energy Systems, Inc.
Calculation of Property Taxes Lead Lag Days
12 Months Ended December 31, 2020
April 2020 Payments

Line No	Description of Payment	Payment Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Check Date	(Lead) Lag Days	Weighted Dollar Days
1	STATE OF NEW HAMPSHIRE	$ 396,927	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	4/6/20 12:00 AM	(177.50)	$ (70,454,543)
2									
3									
4		$ 396,927							$ (70,454,543)
5									
6									
7		Total April 2020 Payments				$ 396,927			
8									
9		Total Weighted Dollar Days				$ (70,454,543)			
10									
11		April 2020 Payments (Lead) Lag Days				(177.50)			
12									
13									
14									
15									

Unitil Energy Systems, Inc.
Calculation of Property Taxes Lead Lag Days
12 Months Ended December 31, 2020
June 2020 Payments

Line No	Description of Payment	Payment Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Check Date	(Lead) Lag Days	Weighted Dollar Days
1	STATE OF NEW HAMPSHIRE	$ 396,927	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	6/10/20 12:00 AM	(112.50)	$ (44,654,288)
2	TOWN OF NORTH HAMPTON	471	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(49,220)
3	TOWN OF ALLENSTOWN NH	1,161	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(121,325)
4	TOWN OF BRENTWOOD NH	1,831	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(191,340)
5	TOWN OF DUNBARTON NH	5,858	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	6/18/20 12:00 AM	(14.00)	(82,015)
6	TOWN OF GREENLAND, NH	220	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(22,990)
7	TOWN OF HAMPSTEAD NH	3,031	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(316,740)
8	TOWN OF HOPKINTON NH	4,623	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(483,104)
9	TOWN OF LOUDON	5,837	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(609,967)
10	TOWN OF PEMBROKE NH	3,906	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(408,177)
11	CITY OF CONCORD NH	440,646	7/1/20 12:00 AM	7/1/21 12:00 AM	365	12/30/20 12:00 PM	6/18/20 12:00 AM	(195.50)	(86,146,307)
12	TOWN OF EAST KINGSTON	48,748	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(5,094,166)
13	TOWN OF STRATHAM	61,844	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(6,462,698)
14	TOWN OF ATKINSON NH	41,965	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(4,385,343)
15	TOWN OF CANTERBURY NH	29,345	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(3,066,553)
16	TOWN OF CHICHESTER NH	67,792	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	6/18/20 12:00 AM	(14.00)	(949,088)
17	TOWN OF DANVILLE	50,163	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(5,242,034)
18	TOWN OF EXETER NH	193,261	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(20,195,822)
19	TOWN OF HAMPTON NH	206,741	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(21,604,435)
20	TOWN OF KINGSTON NH	193,778	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(20,249,806)
21	TOWN OF NEWTON NH	70,599	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(7,377,596)
22	TOWN OF PLAISTOW	118,233	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(12,355,349)
23	TOWN OF SALISBURY NH	32,414	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(3,387,263)
24	TOWN OF EPSOM NH	59,138	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(6,179,921)
25	TOWN OF KENSINGTON NH	82,817	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(8,654,377)
26	TOWN OF SEABROOK	99,934	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(10,443,103)
27	TOWN OF WEBSTER	12,720	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	6/18/20 12:00 AM	(104.50)	(1,329,240)
28									
29									
30		$ 2,234,004							$ (270,062,260)
31									
32									
33		Total June 2020 Payments				$ 2,234,004			
34									
35		Total Weighted Dollar Days				$ (270,062,260)			
36									
37		June 2020 Payments (Lead) Lag Days				(120.89)			
38									
39									
40									

Unitil Energy Systems, Inc.
Calculation of Property Taxes Lead Lag Days
12 Months Ended December 31, 2020
July 2020 Payments

Line No	Description of Payment	Payment Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Check Date	(Lead) Lag Days	Weighted Dollar Days
1	TOWN OF BOSCAWEN NH	$ 122,334	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	7/1/20 12:00 AM	(1.00)	$ (122,334)
2	TOWN OF BOW NH	136,462	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	7/1/20 12:00 AM	(91.50)	(12,486,273)
3	TOWN OF HAMPTON FALLS	44,212	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	7/1/20 12:00 AM	(91.50)	(4,045,398)
4	TOWN OF SOUTH HAMPTON	19,376	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	7/1/20 12:00 AM	(91.50)	(1,772,904)
5									
6									
7		$ 322,384							$ (18,426,909)
8									
9									
10		Total July 2020 Payments				$ 322,384			
11									
12		Total Weighted Dollar Days				$ (18,426,909)			
13									
14		July 2020 Payments (Lead) Lag Days				(57.16)			
15									

Unitil Energy Systems, Inc.
Calculation of Property Taxes Lead Lag Days
12 Months Ended December 31, 2020
September 2020 Payments

Line No	Description of Payment	Payment Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Check Date	(Lead) Lag Days	Weighted Dollar Days
1	STATE OF NEW HAMPSHIRE	$ 396,927	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	9/9/20 12:00 AM	(21.50)	$ (8,533,931)
2	CITY OF CONCORD NH	440,646	7/1/20 12:00 AM	7/1/21 12:00 AM	365	12/30/20 12:00 PM	9/28/20 12:00 AM	(93.50)	(41,200,412)
3									
4									
5		$ 837,573							$ (49,734,343)
6									
7									
8		Total September 2020 Payments				$ 837,573			
9									
10		Total Weighted Dollar Days				$ (49,734,343)			
11									
12		September 2020 Payments (Lead) Lag Days				(59.38)			
13									
14									
15									

Unitil Energy Systems, Inc.
Calculation of Property Taxes Lead Lag Days
12 Months Ended December 31, 2020
November 2020 Payments

Line No	Description of Payment	Payment Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Check Date	(Lead) Lag Days	Weighted Dollar Days
1	TOWN OF BOSCAWEN NH	$ 122,728	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	11/30/20 12:00 AM	151.00	$ 18,531,928
2	TOWN OF DANVILLE	43,635	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	11/30/20 12:00 AM	60.50	2,639,918
3	TOWN OF DUNBARTON NH	5,668	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	11/30/20 12:00 AM	151.00	855,835
4	TOWN OF KENSINGTON NH	104,405	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	11/30/20 12:00 AM	60.50	6,316,503
5	TOWN OF PEMBROKE NH	5,698	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	11/30/20 12:00 AM	60.50	344,729
6									
7									
8		$ 282,134							$ 28,688,912
9									
10									
11		Total November 2020 Payments				$ 282,134			
12									
13		Total Weighted Dollar Days				$ 28,688,912			
14									
15		November 2020 Payments (Lead) Lag Days				101.69			

Unitil Energy Systems, Inc.
Calculation of Property Taxes Lead Lag Days
12 Months Ended December 31, 2020
December 2020 Payments

Line No	Description of Payment	Payment Amount	Service Period Start	Service Period End	Total Days	Midpoint Service Period	Check Date	(Lead) Lag Days	Weighted Dollar Days
1	TOWN OF ALLENSTOWN NH	$ 824	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/3/20 12:00 AM	63.50	$ 52,324
2	TOWN OF BRENTWOOD NH	2,215	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/3/20 12:00 AM	63.50	140,653
3	TOWN OF GREENLAND, NH	225	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/3/20 12:00 AM	63.50	14,288
4	TOWN OF HAMPSTEAD NH	6,091	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/3/20 12:00 AM	63.50	386,779
5	TOWN OF HAMPTON FALLS	38,142	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/3/20 12:00 AM	63.50	2,422,017
6	TOWN OF HAMPTON NH	266,373	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/3/20 12:00 AM	63.50	16,914,686
7	TOWN OF HOPKINTON NH	8,471	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/3/20 12:00 AM	63.50	537,909
8	TOWN OF KINGSTON NH	175,316	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/3/20 12:00 AM	63.50	11,132,556
9	TOWN OF SALISBURY NH	28,223	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/3/20 12:00 AM	63.50	1,792,161
10	TOWN OF EAST KINGSTON	90,295	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/16/20 12:00 AM	76.50	6,907,568
11	TOWN OF CHICHESTER NH	55,038	1/1/20 12:00 AM	1/1/21 12:00 AM	366	7/2/20 12:00 AM	12/16/20 12:00 AM	167.00	9,191,346
12	TOWN OF LOUDON	6,949	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/16/20 12:00 AM	76.50	531,599
13	STATE OF NEW HAMPSHIRE	304,573	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/16/20 12:00 AM	76.50	23,299,835
14	TOWN OF ATKINSON NH	62,047	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/16/20 12:00 AM	76.50	4,746,596
15	TOWN OF NORTH HAMPTON	1,561	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/23/20 12:00 AM	83.50	130,344
16	TOWN OF CANTERBURY NH	49,978	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/23/20 12:00 AM	83.50	4,173,163
17	TOWN OF EPSOM NH	44,183	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/23/20 12:00 AM	83.50	3,689,247
18	TOWN OF NEWTON NH	45,502	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/23/20 12:00 AM	83.50	3,799,417
19	TOWN OF SOUTH HAMPTON	24,715	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/23/20 12:00 AM	83.50	2,063,703
20	TOWN OF WEBSTER	44,853	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/23/20 12:00 AM	83.50	3,745,226
21	CITY OF CONCORD NH	473,161	7/1/20 12:00 AM	7/1/21 12:00 AM	365	12/30/20 12:00 PM	12/23/20 12:00 AM	(7.50)	(3,548,706)
22	TOWN OF STRATHAM	105,261	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/23/20 12:00 AM	83.50	8,789,294
23	TOWN OF EXETER NH	347,986	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/23/20 12:00 AM	83.50	29,056,833
24	TOWN OF PLAISTOW	185,605	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/23/20 12:00 AM	83.50	15,498,018
25	TOWN OF SEABROOK	175,315	4/1/20 12:00 AM	4/1/21 12:00 AM	365	9/30/20 12:00 PM	12/23/20 12:00 AM	83.50	14,638,797
26									
27									
28		$ 2,542,901							$ 160,105,645
29									
30									
31		Total December 2020 Payments				$ 2,542,901			
32									
33		Total Weighted Dollar Days				$ 160,105,645			
34									
35		December 2020 Payments (Lead) Lag Days				62.96			

Unitil Energy Systems, Inc.
Calculation of Income Taxes Lead Lag Days
12 Months Ended December 31, 2020
Federal Income Tax

Line No	Type of Payment	Tax Period Start	Tax Period End	Total Days	Midpoint Service Period	Scheduled Payment Date	(Lead) Lag Days	Statutory % of Total Taxes for Year	Weighted Days
1									
2	First Payment	1/1/20 12:00 AM	4/1/20 12:00 AM	91	02/15/20	4/15/20 12:00 PM	60.0	25.00%	15.00
3									
4	Second Payment	4/1/20 12:00 AM	7/1/20 12:00 AM	91	05/16/20	6/15/20 12:00 PM	30.0	25.00%	7.50
5									
6	Third Payment	7/1/20 12:00 AM	10/1/20 12:00 AM	92	08/16/20	9/15/20 12:00 PM	30.5	25.00%	7.63
7									
8	Fourth Payment	10/1/20 12:00 AM	1/1/21 12:00 AM	92	11/16/20	12/15/20 12:00 PM	29.5	25.00%	7.38
9									
10									
11									
12	Total			366					37.50
13									
14									
15									
16									
17									
18									
19									
20									

Unitil Energy Systems, Inc.
Calculation of Income Taxes Lead Lag Days
12 Months Ended December 31, 2020
State Income Tax

Line No	Type of Payment	Tax Period Start	Tax Period End	Total Days	Midpoint Service Period	Scheduled Payment Date	(Lead) Lag Days	Statutory % of Total Taxes for Year	Weighted Days
1									
2	First Payment	1/1/20 12:00 AM	4/1/20 12:00 AM	91	02/15/20	4/15/20 12:00 PM	60.0	25.00%	15.00
3									
4	Second Payment	4/1/20 12:00 AM	7/1/20 12:00 AM	91	05/16/20	6/15/20 12:00 PM	30.0	25.00%	7.50
5									
6	Third Payment	7/1/20 12:00 AM	10/1/20 12:00 AM	92	08/16/20	9/15/20 12:00 PM	30.5	25.00%	7.63
7									
8	Fourth Payment	10/1/20 12:00 AM	1/1/21 12:00 AM	92	11/16/20	12/15/20 12:00 PM	29.5	25.00%	7.38
9									
10									
11									
12	Total			366					37.50
13									
14									
15									
16									
17									
18									
19									
20									

[THIS PAGE INTENTIONALLY LEFT BLANK]

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY

OF

TODD R. DIGGINS

EXHIBIT TRD-1

New Hampshire Public Utilities Commission

Docket No. DE 21-030

TABLE OF CONTENTS

SCHEDULES

I. INTRODUCTION

Q. Please state your name and business address.

A. Todd R. Diggins, 6 Liberty Lane West, Hampton, New Hampshire 03842.

Q. What is your position and what are your responsibilities?

A. I am the Treasurer and Director of Finance for Unitil Service Corp. ("Unitil Service"), a subsidiary of Unitil Corporation ("Unitil Corp") that provides managerial, financial, regulatory, engineering and information technology services to Unitil Corp's subsidiaries. I am also the Treasurer of Unitil Energy Systems, Inc. ("UES" or "Company") and Unitil Corp's other utility subsidiaries. My responsibilities are primarily in the areas of financial planning and analyses, regulatory projects, treasury operations, investor relations, and insurance and loss control programs.

Q. Please describe your business and educational background.

A. I have over 20 years of professional experience in the utility industry focused within the finance, accounting and regulatory areas. I joined Unitil Service in 1998 as a Systems Financial Analyst. In 2004 I accepted a position within the Accounting Department as a General Accountant and was promoted to Corporate Accounting Manager in 2009. In 2018 I was promoted to Director of Finance and in 2020 became Treasurer and Director of Finance. I hold a Bachelor of Science degree from the University of New Hampshire, a Master's Degree of Science in

Finance from Southern New Hampshire University, and a Master's of Global Business Administration from Southern New Hampshire University.

Q. Do you hold any professional licenses?

A. Yes, I am a Certified Public Accountant in the State of New Hampshire.

Q. Have you previously testified before this Commission?

A. Yes, I have testified before the New Hampshire Public Utilities Commission ("NHPUC" or "Commission") on various financial matters. Most recently I submitted testimony supporting the Company's application to issue securities in Docket DE 20-076. I have also testified before the Maine Public Utilities Commission and Massachusetts Department of Public Utilities on several occasions.

Q. Were your testimony and exhibits prepared by you or under your direct supervision?

A. Yes, they were.

II. SUMMARY AND OVERVIEW OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the Company's proposed capital structure to be used for ratemaking purposes, support the Company's proposed long-term cost of debt rate, support the proposed rate of return on rate base, and petition the Commission for a waiver to change the Company's existing short-term debt formula pursuant to RSA 369:7 and N.H. Admin. Rule Puc 307.05. My testimony also discusses rating agency actions and other factors that may affect the Company's ability to efficiently and effectively access long-term capital.

Q. Please summarize the Company's proposed capital structure for ratemaking purposes.

A. As detailed on Schedules RevReq-5[1] and RevReq-5-1, the Company's proposed capital structure consists of 52.91% common equity, 0.10% preferred stock equity, 46.99% long-term debt, and 0.00% short-term debt.

Q. Please summarize the Company's proposed cost of long-term debt.

A. The calculation of the cost of long-term debt for UES is detailed on Schedule RevReq-5-4, which shows the weighted cost rate of 5.49% that was calculated by using the "Net Proceeds" methodology, consistent with Commission precedent.

Q. Please summarize the Company's proposed overall Return on Rate Base.

A. As summarized on Schedule RevReq-5, the Company's proposed Return on Rate Base is 7.88%.

Q. Please summarize the Company's proposed change to the existing short-term debt limit.

[1] References in my testimony to "Schedule RevReq-XX" are to the revenue requirement schedules sponsored by UES witness Christopher J. Goulding and Daniel T. Nawazelski.

A. The current authorized borrowing limit is based on a formula sets the short-term debt limit at the sum of (1) 10% of Net Utility Plant reported on the most recent Federal Energy Regulatory Commission ("FERC") Form 1 report, and (2) a constant of $10 million. For the reasons discussed in more detail in Section VI, the Company proposes to increase the constant from $10 million to $20 million.

III. CAPITAL STRUCTURE

Q. Please describe the framework for the proposed capital structure.

A. The proposed capital structure represents the five quarter average as of December 31, 2020 after incorporating a pro forma adjustment for $3.5 million of scheduled debt retirements in 2021. Schedule RevReq 5-1 provides the calculation for the proposed capital structure.

Q. Please explain the pro forma adjustment removing $3.5 million of long-term debt from the average capital structure.

A. The pro forma adjustment reflects required, known and measurable debt retirements that will take place prior to the date new permanent distribution rates are expected to take effect in this proceeding. The pro forma adjustment includes a required debt retirement payment of $2 million of the Company's 6.96% notes in September 2021, and $1.5 million of its 8.49% notes in October 2021.

Q. Does the proposed capital structure include short-term debt?

A. No, the proposed capital structure includes only the sources of long-term capital that fund the long-lived assets included in rate base. Those sources do not include short-term debt. The Company believes it is important to match the long-lived nature of utility assets with similarly termed capital. Short-term debt is used principally to fund seasonal working capital requirements, construction work in process ("CWIP") and long-term debt sinking fund redemptions. As CWIP is not included in rate base, the short-term debt funding associated with CWIP should not be considered in the Company's regulatory capital structure for rate setting purposes. Over time, capital spending and sinking fund requirements will result in short-term debt balances that accumulate to levels that can be rolled into long-term financings. Under that financing cycle, short-term debt balances fall, and the capital structure's term is aligned with the long-term nature of utility assets. For these reasons, the Company does not rely on short-term debt as a permanent element of its capital structure, and does not believe it should be included in the regulatory cost of capital for rate setting purposes.

Q. Why is it appropriate to use a five quarter average capital structure?

A. A five quarter average is more representative of the Company's target capital structure going forward than the point in time capital structure as of December 31, 2020. The point in time capital structure at December 31, 2020 is not illustrative of the Company's planned capital structure as a result of the timing of its recent $27.5 million debt financing in September 2020. I discuss the Company's target capital structure, and the need to maintain that target capital structure, later in my testimony.

Q. How does the proposed capital structure compare to the proxy group?

A. Please refer to Page 1 of Exhibit JEN-10 in Jennifer E. Nelson's testimony. The five quarter average proxy group equity ratio is 53.00%. This is consistent with the Company's proposed equity ratio of 52.91%.

Q. Please explain the primary goals the Company considers when managing its capital structure.

A. The primary goals to consider and balance when managing the capital structure are to (1) minimize the weighted average cost of capital and (2) maintain sufficient equity funding to support the Company's balance sheet and creditworthiness. Capital structure is a measure of financial risk. Debt typically carries a lower cost than equity, but has fixed payment obligations, unlike common equity. Therefore, although debt is less costly, higher debt leverage results in additional financial risk. The Company requires an equity ratio that manages its financial risk and supports its existing investment grade credit ratings. Later in my testimony I discuss other credit rating and market factors that must be considered when determining an appropriate capital structure.

Q. Does the capital structure impact the Cost of Equity?

A. Yes. Investors expect returns to be commensurate with the relative risk of an investment. Given the impact capital structure has on financing risk, it must be considered when determining the Cost of Equity. There is more detailed support of this topic in the direct testimony of Jennifer E. Nelson filed in this Docket.

Q. Do you believe the proposed capital structure for the Company is appropriate?

A. Yes. The proposed capital structure is consistent with the average equity ratio of the proxy group companies, and reflects the industry practice of matching long-term nature of its rate base with the sources of capital used to finance those assets.

IV. COST OF DEBT

Q. What cost of debt has the Company requested in this proceeding?

A. The calculation of the cost of long-term debt for UES is detailed on Schedule RevReq-5-4, which shows the weighted cost rate of 5.49%.

Q. Please discuss your analysis of the Company's proposed Cost of Debt.

A. Please refer to Schedule TRD-1 which tests the reasonableness of the proposed cost of debt. This schedule compares the Company's cost of debt, excluding transaction costs, to the Moody's Bond Yield for both A-Rated Utilities and BAA-Rated Utilities as of the offering dates of the Company's outstanding debt. Given that the Company's cost of debt rate is consistent with these Utility Bond Indices, I conclude that the Company's proposed cost of debt is appropriate and reasonable.

V. RETURN ON RATE BASE

Q. Please summarize the Company's proposed rate of return on rate base.

A. As summarized on Schedule RevReq-5, the Company's proposed return on rate base is 7.88%. This is the sum of the weighted cost of common equity, the cost of preferred equity, and the cost of debt.

Q. Please describe how the cost of capital is weighted.

A. The cost of the various capital components are weighted by the Company's proposed capital structure which is described above.

Q. Please summarize the costs of the various capital components.

A. The cost of common equity of 10.00% to be used for ratemaking purposes as proposed in the prefiled testimony of Robert B. Hevert is below the cost of common equity recommended in the prefiled testimony of Jennifer E. Nelson, and toward the lower end of Ms. Nelson's recommended range. The preferred equity outstanding carries a fixed cost of 6.00%, and the proposed cost of debt is 5.49%.

Q. How does the proposed return on rate base compare to the return authorized in the Company's previous rate case?

A. In Docket DE 16-384 the Commission approved a settlement agreement with Staff and the Office of the Consumer Advocate authorizing a rate of return of 8.34%. The proposed rate of return of 7.88% in this filing is 46 basis points lower, largely due to the lower cost of debt. Our ability to refinance maturing debt at lower rates depends on the strength of our credit profile, including constructive regulatory outcomes.

Q. Do you believe the proposed rate of return on rate base is appropriate?

A. Yes, for the reasons described in my testimony and the testimonies of Mr. Hevert and Ms. Nelson, the Company's proposed rate of return on rate base is reasonable and appropriate.

VI. SHORT-TERM DEBT LIMIT

Q. Please describe the Company's financing cycle.

A. The Company's funding is derived primarily from internally generated funds, which consist of net operating cash flows including depreciation and amortization from operating activities and deferred income taxes. UES supplements internally generated funds through short-term borrowings under the Unitil Corp Cash Pool, which is supported by bank borrowings under Unitil Corp's credit facility. As noted earlier, when UES's short-term balance builds to a sufficient level, it will seek long-term financing to reduce the short-term debt and to appropriately match the long-term utility asset lives with long-term funding.

Q. What is the Company's current short-term borrowing limit?

A. The short-term borrowing limit currently in effect is $34.8 million, which became effective June 1, 2020.

Q. Please explain the current process for establishing the short-term borrowing limit.

A. The borrowing limit is based on a formula filed with the Commission by May 1 each year for effect June 1. The formula consists of 10% of Net Utility Plant reported on the most recent FERC Form 1 report plus a fixed amount of $10 million.

Q. Explain how the current formula for the short-term borrowing limit was established and authorized.

A. On June 12, 2008 UES filed a petition for authority to increase its short-term debt limit and to establish a short-term debt limit formula in Docket DE 08-085. On July 23, 2008, the Commission issued an Order authorizing the Company to increase its short-term debt limit from $16 million to $24 million but deferred a decision on the Company's request to establish a formula pending further examination (Order No. 24,875). On October 22, 2009, the Commission waived Puc Rule 307.05, which limits a utility's short-term indebtedness to 10% of net fixed plant, and approved a Settlement Agreement between Staff and the Company establishing a short-term debt limit formula equal to 10% of Net Utility Plant plus $10 million. Please refer to Schedule TRD-2 which illustrates the authorized borrowing limits over the past 10 years.

Q. Why did the Company file a petition to increase its short-term borrowing limit in Docket DE 08-085?

A. The Company's prior petition to increase the short-term borrowing limit was largely predicated on higher working capital as a result of increasing purchased power and transmission expense, cash obligations for credit assurance as a participant in New England ISO, ongoing energy-related stranded cost obligations and increasing capital expenditures. The Company testified that reducing the frequency of long-term permanent financings created savings by reducing transaction costs and better optimized the offering size of the permanent financings.

Q. Is the Company requesting a waiver of Puc 307.05 to change the short-term borrowing limit formula in this docket?

A. Yes. The Company is requesting a waiver from the Commission of Puc 307.05 to change its existing short-term debt formula pursuant to Puc 201.05 regarding requests for waivers of Commission rules.

Q. Does this petition meet the requirements of Puc 201.05?

A. Yes, the proposed formula change is consistent with Puc 201.05 allowing the Commission to waive the provisions of a rule. As I explain in more detail later in my testimony, the proposed formula change to the short-term debt limit will serve the public's interest by allowing the Company more flexibility in the timing of issuing permanent financing, lowering transaction costs and decreasing the amount of Company resources allocated to issuing permanent financing. The proposed formula change is justified in that it reflects the Company's current borrowing requirements, and is a reasonable alternative method that will allow for the orderly and efficient determination of the Company's short-term debt authorization.

Q. What is the Company's proposed change to the currently authorized borrowing limit formula?

A. The Company is proposing to continue using 10% of net plant as the basis for the formula, but change the fixed component of $10 million, currently authorized in the formula, to $20 million.

Q. When do you propose the new formula take effect?

A. The Company requests that the formula first take effect June 1, 2022, after a final order is expected in this docket.

Q. Are you proposing to change or add anything else to the existing process for establishing the Company's short-term borrowing limit?

A. No. The only proposed change is to the fixed component.

Q. Please elaborate on the need for the proposed change to the current formula approved by the Commission.

A. The Company is requesting a higher short-term borrowing limit primarily to account for retirements of long-term debt. The Company has several Serial Bonds outstanding that have been maturing at regular intervals since 2015. Unlike Term Bonds where the entirety of the principal matures on a single date, Serial Bonds mature at staggered dates and therefore provide more flexibility to the Company to recapitalize the maturing debt at appropriate times and reduce refinance risk. The Company's various Serial Bonds have maturity dates spanning up to 10 years. The staggered debt retirements are often referred to as sinking fund payments. From 2016 to 2020, sinking fund payments at UES totaled $28 million, and over the next five years payments will total $19 million. Please refer to Schedule TRD-3, which illustrates both the historical and projected sinking fund payments. When sinking fund payments are due, unless the Company has sufficient cash on hand, the sinking fund payments are immediately funded with short-term debt. Due to the Company's sinking fund payment schedule, short-term borrowings are increasing at a faster rate than they were before 2015. As a result, the Company has had to pursue long-term financings more frequently. Without additional flexibility the benefits of the Serial Bond structure are diminished.

Q. Please summarize the Company's recent long-term financings.

A. The Company has recently issued long-term debt twice within a span of two years. In November of 2018, the Company closed on $30 million of long-term debt at a rate of 4.18%, and in September of 2020, the Company closed on $27.5 million of long-term debt at a rate of 3.58%. Prior to these financings, the Company had not issued long-term debt since 2010 when it closed on $15 million of debt with an interest rate of 5.24%. Please refer to Schedule TRD-4 which shows the last 10 years of financing history at UES and illustrates the increasing frequency of financing activity in recent years. The reason for the recent financings were not entirely as a result of sinking fund payments, but they were a significant driver. As of December 31, 2020 the sinking fund payments that have retired since 2015 total $31 million; over that same period of time the Company has issued $57.5 million of long-term debt. The Company is responsible for managing its capital structure and borrowing requirements in a prudent manner, and will continue to rely on long-term financings to better match the long-term nature of the utility assets and recapitalizing short-term debt as appropriate. However, without increasing the short-term borrowing limit the Company has less long-term financing flexibility and is prevented from increasing the size of the offerings.

Q. Does the Company have any permanent financings planned over the next two years?

A. No. The Company is regularly evaluating its capital needs, but at this point has no definitive plans for its next permanent financing with regard to structure, timing or sizing.

Q. Can you illustrate the relative pressure the Sinking fund payments are having on short-term borrowings?

A. Yes. Please refer to Schedule TRD-5 for a 10 year history of the Company's short-term borrowings and accompanying limits. This schedule illustrates how borrowings have increased quicker in recent years, in large part due to sinking fund payments. Please also refer to Schedule TRD-6 for an illustrative example of the Company's short-term borrowing forecast from 2021 to 2023. This Schedule also shows the short-term borrowing forecast excluding the funding of all debt retirement payments. The increasing divide between the two lines reflects the relative pressure on the borrowing limit as a result of the sinking fund payments. In this illustrative scenario, the Company would need to seek a permanent financing approximately a full year sooner without the higher proposed borrowing limit. The proposed borrowing limit allows the Company to reduce the frequency of long-term financings.

Q. Please explain how you arrived at the proposed increase of $10 million.

A. The Company would prefer to pursue debt financings at a minimum interval of three years to keep transaction costs low and to lessen the demands on Company's resources when issuing securities. To achieve this, the Company needs to be able to fund debt retirement payments with short-term borrowings between permanent financings. Please again refer to Schedule TRD-3 which shows the rolling three year total of sinking fund payments. Over the next 10 years, the average rolling three year total of sinking fund payments is approximately $11.9 million. The Company believes that a $10 million increase to the limit approximates the amount of sinking fund payments that short-term borrowings must fund over a three year period to provide financing flexibility.

Q. Please explain why it is beneficial to ratepayers to increase the short-term borrowing limit.

A. It is beneficial to ratepayers to increase the short-term borrowing limit because the result will be less frequent long-term debt offerings. By increasing the short-term debt limit the Company has flexibility to access capital markets during more favorable periods and increase the size of the financings. Larger debt offerings tend to be more efficient and can attract more investor interest in the private placement market, which the Company accesses to issue long-term debt, resulting in more competitive pricing. Less frequent financings also have the benefit of spreading issuance costs, such as legal fees, over larger amounts of capital and reducing the Company's resources used when organizing and executing long-term financings.

VII. CREDIT RATINGS AND OTHER MARKET CONSIDERATIONS

Q. Please discuss the Company's current credit ratings.

A. UES has an issuer rating of BBB+ from Standard & Poor's ("S&P") rating agency and an issuer rating of Baa1 from Moody's, both of which are considered "investment grade." The S&P credit rating is determined based on Unitil Corp's entire suite of subsidiaries. The Moody's credit rating is specific to UES.

Q. Are the Company's credit ratings consistent with the peer group?

A. Yes. The table below compares the Company's credit ratings to the credit ratings of the holding companies of the utility peers group introduced in the testimony of Jennifer E. Nelson. The results reflect that the Company's credit ratings are largely consistent with its peers.

Table 1: Credit Rating Benchmarking

Issuer Credit Rating

S&P			**Moodys**		
Rating	**Peer #**	**Peer %**	**Rating**	**Peer #**	**Peer %**
A-	10	41.7%	A3	3	12.5%
BBB+	8	33.3%	Baa1	11	45.8%
BBB	5	20.8%	Baa2	10	41.7%
BBB-	1	4.2%	Baa3	0	0.0%
	24	100.0%		24	100.0%

Notes
Credit Ratings as of 02/23/2021. The peer group is the same as the holding companies used in the capital structure benchmarking.

Q. Have there been any recent changes to the Company's credit ratings?

A. Yes. S&P recently revised Unitil Corp's outlook from stable to negative. Please refer to Schedule TRD-7 for a publication of the announcement on November 5, 2020.

Q. Please summarize the reason for the outlook change and the potential implications.

A. S&P cited Unitil Corp's smaller size relative to peers, weaker financial measures expected in the future as a result of deteriorating economic conditions related to the pandemic and warmer than normal winter weather in 2020. S&P observes that Unitil Corp's sales margins have become more uncertain as a result of the pandemic without decoupled revenue mechanisms in place. Credit rating agencies are quick to respond to negative events or elevated risk, but are slower to reestablish or upgrade an issuer when positive developments occur. They instead will wait for an extended period of time to ensure the measure leads to a long-lasting improvement rather than only a temporary measure. S&P indicated it could downgrade the Company if the funds from operations to debt ratio doesn't improve and consistently achieve at least 16%. The impact of a credit downgrade would increase the perceived investment risk of Unitil Corp to current and prospective investors, and likely increase the Company's cost of capital. The ability to attract competitive sources of capital, especially in times of economic stress, is key to UES continuing to provide exceptional service to the communities it serves at competitive rates.

Q. When considering the Company's proposed capital structure are there any other significant factors that should be considered?

A. Yes. Credit rating agencies make a variety of adjustments to the financial statements when determining credit metrics. The most significant adjustment is the inclusion of Unitil Corp's retirement benefit obligations as imputed debt. Imputed debt unfavorably impacts solvency metrics that compare cash flow to debt. Schedule TRD-8 shows the recent history of the underfunded retirement benefit obligations as well as the discount rate used to determine the benefit obligation. As of December 31, 2020 the imputed debt for these obligations was approximately $129 million. This is equal to about 22% of Unitil Corp's total debt on the books as of December 31, 2020, reflecting the materiality of this credit rating adjustment. Under the S&P methodology, the underfunded obligation is lowered by the federal income tax when calculating the imputed debt. The impact of the lower federal income tax rate, as a result of the Tax Cuts and Jobs Act of 2017, had the impact of increasing the level of imputed debt. Using the S&P methodology, the imputed debt for retirement benefit obligations has increased over $30 million from 2016 to 2020 and is largely due to the lower federal tax rate and a lower discount rate. To maintain investment grade credit metrics Unitil Corp (and its subsidiaries, including UES) must maintain a strong equity ratio to offset the retirement benefit debt imputed by credit rating agencies.

Q. Please describe the Company's plan to support its credit ratings.

A. The Company has increased its target equity ratio range in order to strengthen its balance sheet and offset the impact of the imputed debt. Secondly, the Company has proposed a decoupled revenue mechanism in this docket[2] which will be credit supportive as a result of more stable revenues. Finally, by implementing multiyear rate plans the Company can recover capital costs quicker, thereby reducing the volatility of financial metrics over time. The Company's proposed multiyear rate plan in this filing is included in the joint testimony of Messrs. Daniel T. Nawazelski and Christopher J. Goulding. The importance approval of a multiyear rate plan similar to what the Commission approved in UES' recent base rate case proceedings cannot be overstated. A multiyear rate plan supports the Company's

[2] Please see the Testimony of Timothy S. Lyons.

investment in the distribution system and helps maintain consistent financial health.

Q. Are there any other market considerations you would like to address?

A. Yes. Unitil Corp's small size relative to our utility peers poses challenges to the Company's credit ratings and to equity investors.

Q. Please outline the small size risk on credit ratings.

A. As noted above, both S&P and Moody's consider Unitil Corp's smaller relative size and scale to be a credit challenge. Specifically, S&P considers Unitil Corp's smaller relative customer base as a risk to the Company's business profile. Please see Schedule TRD-9, Confidential and Schedule TRD-10, Confidential for the most recent credit reports published by S&P and Moody's, respectively.

Q. Please demonstrate Unitil Corp's size relative to its utility peers.

A. The table below illustrates the market capitalization of Unitil Corp and its peer utilities. Unitil Corp has the smallest market capitalization of its utility peer group. Unitil Corp's market capitalization is less than half the size of Otter Tail Corporation, the smallest market capitalization company in the peer group.

Table 2: Market Capitalization Benchmarking

Average Daily Capitalization for Calendar Year 2020 ($ millions)			
COMPANY	TICKER	MARKET CAPITALIZATION	
NextEra Energy, Inc.	NEE	$	130,734
Duke Energy Corporation	DUK		64,530
Southern Company	SO		61,312
American Electric Power Company, Inc.	AEP		42,761
Xcel Energy Inc.	XEL		35,016
WEC Energy Group, Inc.	WEC		29,719
Eversource Energy	ES		29,205
Public Service Enterprise Group Incorporated	PEG		27,186
Consolidated Edison, Inc.	ED		26,416
DTE Energy Company	DTE		22,270
Entergy Corporation	ETR		20,988
Ameren Corporation	AEE		19,160
CMS Energy Corporation	CMS		17,540
Evergy, Inc	EVRG		13,350
Alliant Energy Corporation	LNT		13,010
Pinnacle West Capital Corporation	PNW		9,143
OGE Energy Corp.	OGE		6,752
IDACORP, Inc.	IDA		4,692
Hawaiian Electric Industries, Inc.	HE		4,234
Portland General Electric Company	POR		4,076
ALLETE, Inc.	ALE		3,166
NorthWestern Corporation	NWE		3,002
Avista Corporation	AVA		2,717
Otter Tail Corporation	OTTR		1,736
Unitil Corporation	UTL		710

Q. Explain how the smaller relative size increases risk to shareholders.

A. Unitil Corp's relatively small market capitalization typically results in lower trading volumes and less liquidity due to fewer shares outstanding. Market liquidity risk is the risk that an investor cannot quickly buy or sell an asset without impacting the market price. To put it another way, investors that would like to materially increase or decrease their positon in a smaller company have a harder time doing so without causing price changes given the relatively low liquidity. The table below further illustrates that Unitil Corp's daily trading volume is notably lower than the utility peer group average.

Table 3: Average Daily Volume Benchmarking

Average Daily Volume to Average Daily Shares Outstanding						
DESCRIPTION	**2016**	**2017**	**2018**	**2019**	**2020**	**Avg.**
Unitil Corporation	0.32%	0.31%	0.32%	0.33%	0.51%	0.36%
Peer Group Mean	0.60%	0.51%	0.66%	0.56%	0.64%	0.59%
Peer Group Median	0.60%	0.50%	0.65%	0.57%	0.64%	0.59%

Notes
Source: S&P Global Market Intelligence

Q. Is lower liquidity a concern for some investors?

A. Yes, liquidity is an important consideration to institutional investors as they tend to buy and sell large equity positions of a company. The term "institutional investors" refers to large organizations that make substantial investments, such as banks, hedge funds, pension funds, investment advisors, etc. These investors usually require a minimum dollar amount to invest in a particular asset in order to efficiently manage their portfolio. As mentioned previously, these companies could face difficulty acquiring or divesting a position without adversely affecting the market price of the shares.

Q. Can institutional investors be a benefit to a company like Unitil Corp?

A. Yes, capital intensive companies such as UES, and its parent Unitil Corp, can benefit from institutional investors because they provide an efficient source of capital due to the amount of resources they are able to invest. Institutional investors typically account for 70% to 80% of utility share ownership. The peer group's institution ownership currently has an average of 75%, compared to Unitil

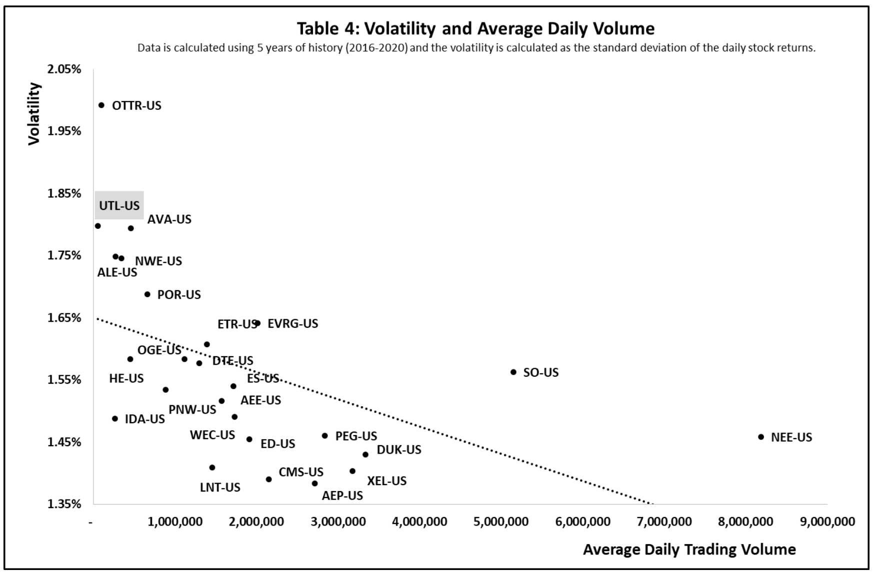
Corp's institutional ownership of 67%. In order to attract institutional investors the expected return must compensate investors for the associated risk of the investment. Specifically, all else held constant the expected return associated with a company with relatively more market liquidity risk would need to be higher than a company with relatively less market liquidity risk.

Q. Can you further demonstrate the effects of Unitil Corp's small size in relation to the cost of equity?

A. Yes, unlike debt that has contractually defined characteristics and a specific assigned interest rate the cost of equity is harder to estimate. Debt holders are given priority to cash flows before equity investors. This uncertainty and additional risk is what compels equity investors to require a higher return than debt investors.

One method of assessing equity risk is to view an equity security's market volatility compared against similar equity securities. The greater the riskiness of the stock the higher the required return is for investors. In this testimony I have referred to the peer group developed in Jennifer E. Nelson's testimony. When looking at this group compared to Unitil Corp some key features stand out. I have already discussed the low average daily trading volume of Unitil Corp compared against it peers. Another attribute is the higher stock volatility of Unitil Corp. Stock volatility is the measure of fluctuation of the price of a stock over a period of time. When analyzing the two measures (average daily trading volume and stock volatility) in Table 4, it is clear that Unitil Corp has higher volatility and lower average daily trading volume compared against other companies in the peer group.

The combination of low daily trading volume and increased volatility are characteristics that can drive investment decisions of investors. Unitil Corp is much smaller in size and has higher volatility than its peers, so it requires a return that is higher than its peers to compensate investors.



Q. What consideration should be given in this docket pertaining to UES's credit metrics, small company size, low liquidity and high volatility?

A. The pressure on credit metrics, the Company's small size, liquidity risk and high volatility should be considered when the Commission is considering the Company's proposed Cost of Equity and capital structure. In Jennifer E. Nelson's direct testimony she approximates that the small size risk premium to the cost of equity is approximately 180 basis points. These considerations support a Cost of

Equity result in the upper end of Jennifer E. Nelson's range, especially when comparing against a peer group that does not face similar difficulties.

VIII. CONCLUSION

Q. Do you believe the proposed capital structure, proposed return on rate base, and the petition to increase the short-term borrowing limit are reasonable?

A. Yes.

Q. Does this conclude your testimony?

A. Yes.

[THIS PAGE INTENTIONALLY LEFT BLANK]

UNITIL ENERGY SYSTEMS, INC.
COST OF LONG-TERM DEBT COMPARISON
AS OF DECEMBER 31, 2020

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
									PROFORMED	MOODY'S BOND YIELD	
LINE NO.	ISSUE	ISSUE DATE	MATURITY DATE	COUPON RATE	TENOR	INITIAL OFFERING	AMOUNT OUTSTANDING	PROFORMA ADJUSTMENT	AMOUNT OUTSTANDING	UTILITY A-RATED	UTILITY BAA-RATED
1	Series I	10/14/1994	10/14/2024	8.49%	30 Yrs	$ 6,000,000	$ 1,200,000	$ (600,000)	$ 600,000	8.76%	9.37%
2	Series J	9/1/1998	9/1/2028	6.96%	30 Yrs	10,000,000	8,000,000	(1,000,000)	7,000,000	6.99%	7.20%
3	Series K	5/1/2001	5/1/2031	8.00%	30 Yrs	7,500,000	7,500,000	-	7,500,000	7.98%	8.09%
4	Series L	10/14/1994	10/14/2024	8.49%	30 Yrs	9,000,000	1,800,000	(900,000)	900,000	8.76%	9.37%
5	Series M	9/1/1998	9/1/2028	6.96%	30 Yrs	10,000,000	8,000,000	(1,000,000)	7,000,000	6.99%	7.20%
6	Series N	5/1/2001	5/1/2031	8.00%	30 Yrs	7,500,000	7,500,000	-	7,500,000	7.98%	8.09%
7	Series O	9/26/2006	9/26/2036	6.32%	30 Yrs	15,000,000	15,000,000	-	15,000,000	5.85%	6.13%
8	Series Q	11/30/2018	11/30/2048	4.18%	30 Yrs	30,000,000	30,000,000	-	30,000,000	4.53%	5.07%
9	Series R	9/15/2020	9/15/2040	3.58%	20 Yrs	27,500,000	27,500,000	-	27,500,000	2.84%	3.16%
10	TOTAL					$ 122,500,000	$ 106,500,000	$ (3,500,000)	$ 103,000,000		
11	WEIGHTED AVERAGES			5.33%						5.17%	5.51%

Notes

Sources: Schedule RevReq 5-4 and S&P Global Market Intelligence.
Weighted average cost of debt rates are based on the Proformed Outstanding Amounts and do not include transaction costs. Moodys Bond Yield figures are as of the offering date of the relevant Notes.

UNITIL ENERGY SYSTEMS, INC.
HISTORICAL SHORT-TERM DEBT LIMITS

	(1)	(2)	(3)
LINE NO.	YEAR	AMOUNT [1]	CAGR [2]
1	2011	$ 25,008,257	-
2	2012	25,573,440	2.3%
3	2013	26,810,488	3.5%
4	2014	26,936,217	2.5%
5	2015	27,869,777	2.7%
6	2016	29,121,025	3.1%
7	2017	30,488,676	3.4%
8	2018	31,686,298	3.4%
9	2019	32,299,751	3.2%
10	2020	34,794,001	3.7%

Notes
(1) Annual limits take effect June 1
(2) The base used in the CAGR calculations is 2011

UNITIL ENERGY SYSTEMS, INC.
LONG-TERM DEBT RETIREMENTS
HISTORICAL AND PROJECTED AS OF DECEMBER 31, 2020

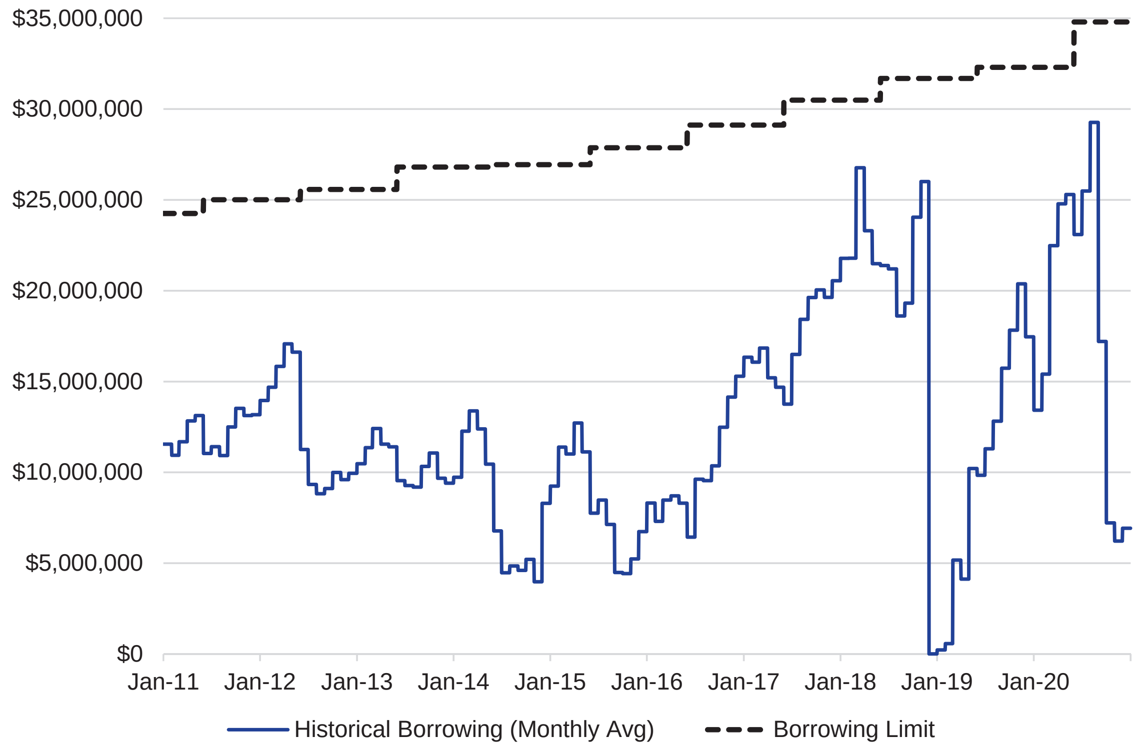
	(1)	(2)	(3)	(4)
LINE NO.	YEAR	RETIREMENTS (HISTORICAL)	RETIREMENTS (PROJECTED)	ROLLING THREE YEAR SUM
1	2005	$ -	$ -	$ -
2	2006	-	-	-
3	2007	-	-	-
4	2008	-	-	-
5	2009	-	-	-
6	2010	-	-	-
7	2011	-	-	-
8	2012		-	-
9	2013		-	-
10	2014		-	-
11	2015	3,000,000	-	-
12	2016	3,000,000	-	-
13	2017	1,500,000	-	7,500,000
14	2018	6,500,000	-	11,000,000
15	2019	8,500,000	-	16,500,000
16	2020	8,500,000	-	23,500,000
17	2021	-	3,500,000	20,500,000
18	2022	-	5,000,000	17,000,000
19	2023	-	3,500,000	12,000,000
20	2024	-	3,500,000	12,000,000
21	2025	-	3,500,000	10,500,000
22	2026	-	3,500,000	10,500,000
23	2027	-	3,500,000	10,500,000
24	2028	-	3,500,000	10,500,000
25	2029	-	1,500,000	8,500,000
26	2030	-	1,500,000	6,500,000
27	TOTAL	$ 31,000,000	$ 32,500,000	$ 12,642,857 AVERAGE (1)

Notes
(1) Simple average from 2017 to 2030

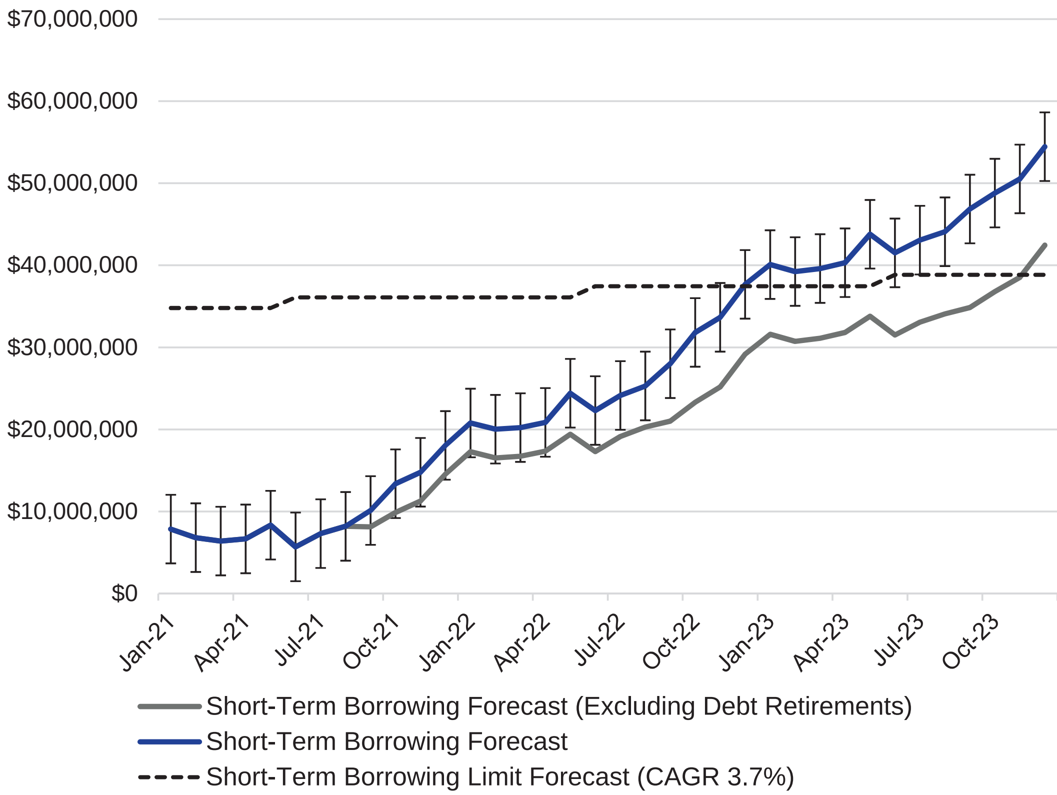
UNITIL ENERGY SYSTEMS, INC.
HISTORICAL FINANCING PROCEEDS
AS OF DECEMBER 31, 2020

	(1)	(2)	(3)	(4)
LINE NO.	YEAR	EQUITY	LONG-TERM DEBT	TOTAL
1	2011	$ -	$ -	$ -
2	2012	5,000,000	-	5,000,000
3	2013	-	-	-
4	2014	-	-	-
5	2015	5,000,000	-	5,000,000
6	2016	-	-	-
7	2017	-	-	-
8	2018	-	30,000,000	30,000,000
9	2019	12,000,000	-	12,000,000
10	2020	7,750,000	27,500,000	35,250,000
11	TOTAL	$29,750,000	$57,500,000	$87,250,000

**UNITIL ENERGY SYSTEMS, INC.
HISTORICAL SHORT-TERM BORROWINGS
AS OF DECEMBER 31, 2020**



UNITIL ENERGY SYSTEMS, INC.
FORECASTED SHORT-TERM BORROWINGS
AS OF DECEMBER 31, 2020



Notes

(1) The error bars represent two standard deviations of intermonth borrowings compared to the average borrowings in the month

(2) The borrowing limit was forecasted under the currently authorized formula by using the 10 year historical growth rate of 3.7%

S&P Global
Ratings

RatingsDirect®

Research Update:

Unitil Corp. And Subsidiaries Outlooks Revised To Negative On Weaker Consolidated Financial Measures; Ratings Affirmed

November 5, 2020

PRIMARY CREDIT ANALYST

William Hernandez
Farmers Branch
+ 1 (214) 765-5877
william.hernandez
@spglobal.com

SECONDARY CONTACT

Gerrit W Jepsen, CFA
New York
(1) 212-438-2529
gerrit.jepsen
@spglobal.com

Rating Action Overview

- U.S. utility holding company Unitil Corp.'s consolidated financial measures have weakened from historical levels due to weaker cash flows and greater leverage.
- As such, we are revising our rating outlook on Unitil Corp. and subsidiaries Northern Utilities Inc. (NU), Fitchburg Gas & Electric Light Co. (FG&E), Unitil Energy Systems Inc. (UES), and Granite State Gas Transmission Inc. to negative from stable.
- We are affirming our issuer credit ratings on each entity, including our 'BBB+' issuer credit ratings.
- The negative outlook reflects the potential for a one-notch downgrade over the next 24 months if Unitil's consolidated financial measures do not improve, including funds from operations (FFO) to debt consistently above 16%.

Rating Action Rationale

The negative outlook reflects the increased possibility that Unitil might not consistently achieve FFO to debt of at least 16%. As a result of weaker economic conditions related to the pandemic, lower gas and electric sales margins primarily due to warmer winter weather in 2020 compared to 2019, and an elevated capital spending plan, we expect Unitil's financial measures to be pressured over the forecast period. FFO to debt as of the third quarter 2020 was 15.3%, which is below our downgrade trigger. While Unitil benefits from electric and natural gas decoupling in Massachusetts, decoupled margins represent only 25% of consolidated margins. Forward-looking, both UES and NU are required by the Public Utilities Commission of New Hampshire to propose revenue decoupling or alternative lost base revenue mechanisms in their next rate case filing. While we believe this is credit positive, as it could result in about decoupled margins representing about 75% of consolidated margins, Unitil's margins remain exposed to revenue uncertainty at least through next year. Additionally, the company's elevated capital spending needs will likely lead to further debt issuances during our forecast period, which will further pressure credit measures. However, we expect the company will take various steps to mitigate some of the anticipated financial impact of its robust capital spending program and the weaker margins. Under our base case, we expect Unitil will continue to effectively manage its regulatory risk and implement other liquidity/credit-supportive measures, as necessary.

Unitil's five-year capital spending program will increase about 25% compared with the previous five years. Unitil is deploying about $680 million in capital through 2024 to support gas system growth and electric distribution system modernization. While our base case incorporates incremental debt issuances to fund this elevated spending, Unitil operates with capital tracker mechanisms in Maine and Massachusetts that allow for the recovery of costs between base rate cases through rate surcharges.

Our business risk assessment for Unitil incorporates our view of its effective management of regulatory risk. Our assessment of Unitil's business risk reflects its lower-risk, rate-regulated electric and natural gas distribution operations that provide essential services. The company operates under a generally constructive regulatory framework in supportive jurisdictions that allows it to recover costs, including capital spending, through annual adjustments, multiyear rate plans, and capital tracker mechanisms. Unitil also benefits from electric and natural gas decoupling in Massachusetts. Our ratings on Unitil include a comparable ratings analysis modifier that is considered positive to reflect our view that the company's business risk profile is at the upper end of our assessment based on its lower-risk electric and gas distribution operations. Although Unitil serves only around 190,000 customers, the company's expansion projects provide new opportunities to grow its customer base over the next few years.

Because it serves primarily the natural gas needs of affiliate utility Northern Utilities, we assess Granite State's business risk as somewhat less risky compared with other transmission pipelines exposed primarily to third-party marketers.

Unitil's size and exposure to industrial and commercial customers weighs on the business risk profile. Compared to peers, Unitil has fewer customers and its electric and gas utilities have material exposure to a cyclical industrial and commercial customer base (about 40% of electric sales margins and 60% of gas sales margins). However, we expect this exposure to decrease should the proportion of decoupled margins increase.

Outlook

The negative outlook reflects the potential for lower ratings over the next 24 months if we believe Unitil will not be able to consistently achieve consolidated FFO to debt of at least 16%. This could occur from weaker cash flows due to lower sales margins or a lag on timely recovery of capital spending, or if the company uses primarily debt leverage to fund capital spending.

Downside scenario

We could lower the ratings on Unitil and its subsidiaries if financial measures remain weak and result in FFO to debt that is consistently below 16%. This could occur from weaker cash flows driven by lower sales margins or a lag on timely recovery of capital spending, or if the company uses primarily debt leverage to fund capital spending.

Upside scenario

We could revise the outlook to stable if Unitil's financial measures improve to a level that supports the current ratings, demonstrated by FFO to debt of at least 16% consistently, while business risk remains at least as strong as the existing level.

Company Description

U.S.-based Unitil is a holding company of three regulated electric and natural gas distribution utilities serving around 190,000 customers in Massachusetts, Maine, and New Hampshire--FG&E, NU, and UES. Together, these regulated subsidiaries contribute more than 90% of consolidated revenues.

Unitil also operates a FERC-regulated gas transmission pipeline, Granite State, that provides predominantly NU (more than 80% of revenues) and other third-party suppliers with access to domestic and Canadian natural gas.

Our Base-Case Scenario

- Gross margin growth primarily from regulated capital recovery and customer growth in New Hampshire, Maine and Massachusetts.
- Elevated capital spending to support gas system growth and distribution system modernization.
- Capital spending of about $680 million over the next five years.
- Discretionary cash flow deficit that we expect to be funded primarily with debt.

Liquidity

We assess Unitil's liquidity as adequate because the company's sources are likely to cover its uses by more than 1.1x over the next 12 months, even if EBITDA declines by 10%. The company has the likely ability to absorb high-impact, low-probability events without refinancing, has well-established and sound relationships with banks, a generally satisfactory standing in credit markets, and generally prudent risk management.

Principal liquidity sources

- Cash and liquid investments of about $10 million;
- Cash FFO of about $105 million; and
- Revolving credit facility availability of about $100 million.

Principal liquidity uses

- Capital spending of about $130 million;
- Debt maturities of about $25 million; and

- Dividends of about $25 million.

Ratings Score Snapshot

Issuer Credit Rating: BBB+/Negative/--

Business risk: Strong

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Satisfactory

Financial risk: Significant

- Cash flow/leverage: Significant

Anchor: bbb

Modifiers

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Satisfactory (no impact)
- Comparable rating analysis: Positive (+1 notch)

Stand-alone credit profile: bbb+

- Group credit profile: bbb+

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings List

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.standardandpoors.com for further information. Complete ratings information is available to subscribers of RatingsDirect at www.capitaliq.com. All ratings affected by this rating action can be found on S&P Global Ratings' public website at www.standardandpoors.com. Use the Ratings search box located in the left column.

UNITIL ENERGY SYSTEMS, INC.
UNITIL CORPORATION: RETIREMENT BENEFIT OBLIGATIONS FUNDED STATUS
ASSETS VS PROJECTED BENEFIT OBLIGATION
($000's)

	(1)	(2)	(3)	(4)	(5)	(6)
LINE NO.	DESCRIPTION	2016	2017	2018	2019	2020
1	Benefit Obligation Discount Rate	4.10%	3.60%	4.25%	3.25%	2.50%
2	Pension Plan	$ 59,381	$ 64,606	$ 48,389	$ 56,380	$ 68,686
3	PBOP Plan	80,053	73,888	59,896	68,377	73,984
4	SERP	9,566	11,723	13,754	17,759	20,225
5	Total Obligation	$ 149,000	$ 150,217	$ 122,039	$ 142,516	$ 162,895
6	Change (2016 to 2020):					$ 13,895
7	Federal Tax Rate	34.00%	34.00%	21.00%	21.00%	21.00%
8	Imputed Debt *Line 5 x (1 - Line 7)*	$ 98,340	$ 99,143	$ 96,411	$ 112,588	$ 128,687
9	Change (2016 to 2020):					$ 30,347

Notes
Source: SEC Filings. S&P reduces the retirement benefit obligation by the federal tax rate.

Docket No. DE 21-030
Schedule TRD-9
Page 1 of 1
CONFIDENTIAL

Docket No. DE 21-030
Schedule TRD-10
Page 1 of 1
CONFIDENTIAL

[THIS PAGE INTENTIONALLY LEFT BLANK]

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY

OF

SARA M. SANKOWICH

EXHIBIT SMS-1

New Hampshire Public Utilities Commission

Docket No. DE 21-030

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Sara M. Sankowich. My business address is 30 Energy Way, Exeter, New Hampshire 03833.

Q. What is your position and what are your responsibilities?

A. I am the Manager of Forestry Operations & Sustainability of Unitil Service Corp. ("Unitil Service"). My primary responsibility is the planning and management of the electric operations vegetation management program for Unitil Corporation's two electric distribution company subsidiaries, Unitil Energy Systems, Inc. ("UES" or the "Company") and Fitchburg Gas and Electric Light Company ("FG&E").

Q. Please describe your business and educational background.

A. I have over 20 years of professional experience in the utility industry with an extensive background utility vegetation management. I joined Unitil Service in 2011 as the System Arborist. Prior to joining Unitil Service, I was employed for six years at National Grid where I advanced through positions in utility vegetation management. The last position I held with National Grid was that of Manager, Vegetation Management Strategy. Prior to National Grid I held a utility arborist position with Orange & Rockland Utilities, and a position with Northern Indiana Public Service Company as a consultant through Environmental Consultants Inc. I hold a Bachelor of Science degree in Forestry Resource Management from the State University of New York, College of Environmental Science and Forestry.

Q. Do you have any certifications that qualify you to speak to issues related to vegetation management?

A. Yes. I am a Certified Arborist through the International Society of Arboriculture.

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("Commission")?

A. Yes, I have appeared previously before the Commission in multiple reconciliation filing hearings. I have also supplied expert testimony in other state regulatory proceedings relating to vegetation management.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe and provide support for the Company's vegetation management program ("VMP") and the storm resiliency program ("SRP").

Q. Please summarize your testimony.

A. The Company has a comprehensive vegetation management program intended to prevent trees from interfering with electric lines during normal weather conditions and minor storm events. The program's components cost-effectively address the different areas of risk and provide benefits to customers, support favorable reliability, and provide a measure of public safety. The Company is also proposing the continuation of its storm resiliency program, which is the component of the VMP that has been specifically designed to reduce tree exposure along electric overhead lines in order to reduce the overall cost of storm preparation and response, and improve system performance during major storm events.

Q. How have you organized your testimony?

A. My testimony will first discuss the current status of the vegetation management program, including the program's components of cycle pruning, hazard tree mitigation, mid-cycle review, forestry reliability assessment, and sub-transmission maintenance. My testimony will then discuss the storm resiliency program, including a summary of work completed under the program, the recent results of the program, including its costs and benefits.

II. VEGETATION MANAGEMENT PROGRAM, POLICY, AND STRATEGY

Q. Does the Company have a comprehensive vegetation management program to prevent trees from interfering with electric lines?

A. Yes. UES's VMP consists of four main components: cycle pruning; hazard tree mitigation; mid-cycle review; and forestry reliability assessment. Each component of the program is designed to minimize the potential for tree and vegetation contact with the overhead utility lines and the incidence and resulting damage of tree and limb failures from above and alongside the conductors.

Vegetation maintenance pruning and clearing done on a cyclical schedule by circuit is called "cycle pruning." The Company's base cycle length is five years.

A hazard tree is a danger tree (any tree or tree part which, on failure, is capable of interfering with the safe, reliable transmission of electricity) that has both a target and a noticeable defect that increases the likelihood of failure. The hazard tree mitigation component program involves the consolidation of hazard tree removal activities into a formalized program.

The mid-cycle review program component targets circuits for inspection and pruning based on time since last circuit pruning and forecasted next circuit pruning. The aim of this program is to proactively address the fastest growing tree species that will grow into the conductors prior to the next cyclic pruning.

The forestry reliability assessment program component targets circuits for inspection, pruning, and hazard tree removal based on recent historic reliability performance. This allows reactive flexibility to address immediate reliability issues not otherwise addressed by the scheduled maintenance programs, without compromising their integrity.

The overall goals of these integrated components of the VMP are to improve and continue favorable reliability performance, consistent with the Company's ongoing obligation to provide safe and reliable service, and which meet the Commission's expectations and increases customer satisfaction. In addition to these overall goals, cycle pruning and mid-cycle review also aim to provide a measure of public safety by minimizing the potential for direct contact by the public with energized conductors by climbing trees, and indirect contact though vegetation in contact with energized equipment, as well as minimizing the potential for electrically caused fire in trees and brush.

Q. Does the Company have a vegetation management component to respond to unscheduled necessities such as customer calls and emergency needs?

A. Yes. UES's VMP has a non-discretionary or "Core Work" component. This critical component of the VMP allows for the ability to respond to emergencies, customer requests, new construction needs, and other non-discretionary and unscheduled work. A dedicated number of specialized crews are required on site on a year-round basis to address the Company's Core Work needs.

Q. Does the Company have full control over the amount of Core Work completed each year?

A. No. The amount of Core Work completed each year is highly variable as it is comprised of fluctuating components such as customer and emergency needs. More frequent severe weather events can change the quantity of Core Work activities dramatically as restoration and damage needs increase, but also as customers become aware of the consequences of tree and wire conflict and, as a result, request tree work. For this reason, work amount expectations can be easily exceeded due to frequent minor weather events or residual impact of large weather events.

Q. Does the Company have a vegetation management component to maintain the rights-of-way that connect substations together?

A. Yes. The Company has a sub-transmission maintenance component that applies the principles and practices of integrated vegetation management ("IVM") to maintain the rights-of-way. This includes identifying compatible and incompatible vegetation, considering action thresholds, evaluating control methods and selecting and implementing controls to achieve a specific objective. The plants to be controlled are primarily tall growing trees that can grow into or fall onto electric lines. Right-of-way maintenance includes: cyclical floor maintenance such as mowing, hand cutting, and herbicide application; side line pruning; and hazard tree removal.

III. VEGETATION MANAGEMENT PROGRAM COSTS

Q. What are the work component drivers of the VMP's cost?

A. The VMP's costs are driven primarily by the cost to implement cycle pruning, the largest program work category. The second largest program cost is hazard tree mitigation, and the third largest program cost is sub-transmission right-of-way maintenance. A large uncontrollable, but necessary, cost relates to required police protection and flaggers for traffic safety. The Company has limited ability to control these generally increasing costs.

Q. Are there any shared vegetation management costs for jointly-owned poles?

A. Yes. The companies which jointly own poles share vegetation maintenance and storm costs pursuant to the respective Joint Ownership Agreement ("JOA") and the Intercompany Operating Procedures' ("IOP") Joint Trimming process. These procedures are followed to share applicable costs between the joint pole owner companies.

Q. Has the Company reduced its request for recovery of its vegetation management costs by the amounts charged to joint owners under each applicable IOP for tree trimming costs incurred during the test year?

A. No. The Company's request to recover vegetation management costs is not reduced for these amounts because payment by the joint owners is not guaranteed nor always timely, and the integrity of the VMP should not be dependent upon the occurrence of these payments.

Q. **How is the Company proposing to treat the contributions received from joint pole owners towards trimming expenses?**

A. As discussed in the direct testimony of UES witnesses Messrs. Christopher Goulding and Daniel Nawazelski, the Company is proposing to continue the current reconciliation process through the External Delivery Charge mechanism ("EDC"). Any payment received from a joint pole owner will be credited to customers through the EDC reconciliation. As part of that process, the Company will continue to provide its VMP plan for the upcoming project year to Staff and the OCA for review. The Company will make itself available to meet with Staff and the OCA in technical sessions to discuss the plan, obtain comments, and answer any questions regarding the plan to be implemented for that fiscal year. After that review, the Company will take all reasonable steps deemed appropriate to carry out and implement the plan, taking into account the comments received.

Q. What are the benefits to the Company and its customers of continuing the VMP at its current scope?

A. The benefits of continuing the current scope of the VMP are the continuation of greater reliability, customer satisfaction, safety, and maintenance efficiency.

<u>Reliability</u>

There is a risk to reliability improvement and continued favorable reliability performance trends if the there is a reduction or lapse in ongoing implementation of the VMP. The risk of tree related interruptions from grow-in conditions are significantly low when all circuits are kept on their appropriate pruning schedule. Each year approximately 20 percent of the system is being maintained while growth is occurring on the other 80 percent. The risk to reliability increases if the full cycle maintenance scope is not implemented.

Customer Satisfaction

Failure to implement the full scope of the VMP has the potential to result in negative customer satisfaction. Customer expectation of continued reliability would not occur and reliability performance may deteriorate. The perception of proactively managing vegetation to improve reliability performance would be lost and replaced with the perception of a reactive program that is always behind the curve. Negative customer satisfaction can also result in increased customer complaints and requests for individual pruning work, which require more supervisor review and management and increased work and cost to mitigate.

Safety

Not implementing the full scope of the VMP results in risks of public injury, property damage, and liability. In the absence of necessary maintenance there is the risk of electrocution through direct contact in a climbable tree or indirect contact through the tree itself, as well as the risk of fire. The absence of sideline hazard tree mitigation increases risk to life and property through direct contact, or potential for contact through energized conductors being brought down within public contact zones. Tree-caused outages that would be addressed by maintenance work often result in the most significant damage, large amount of customers affected, long duration outages and increased risk to safety. Large trees and limbs bringing conductors down also increases the risk of loss of electric service to municipalities' critical infrastructure and emergency services.

Efficiency

There is a risk to efficiency if the full scope of the VMP is not implemented. Efficiency losses will develop if vegetation is allowed to encroach on the overhead assets, as working around conditions with vegetation growth in close proximity to conductors will slow routine maintenance and typical storm restoration, as well as deter accurate and efficient line inspections. Efficiency and reliability losses may also occur with the potential to delay fault locating when an event occurs.

Q. Has the program seen an increased cost to perform annual work?

A. Yes, the cost to complete the annual VMP has increased in recent years.

Q. What is the largest driver of increasing VMP costs?

A. The cost of contracted labor has been the largest driver of increasing VMP costs over the past recent years. After seeing an increasing trend in market price for line clearance tree pruning, the Company held informational meetings with each bidding vendor individually to determine the driving factors behind the increase in costs. In statements from these vendors, the causes for increased costs compared to costs from 5 years ago were consistent: 1) increased wages for retention and recruitment; 2) increased labor burden driven by health insurance premiums, insurance costs, and auto insurance costs for commercial motor carriers; and 3) increased costs of equipment, tools, and supplies.

Q: Why is there a need for increased wages for retention and recruitment?

A. Line-Clearance vendors have expressed a struggle throughout the industry with recruitment of new applicants and retention of existing workers, driven by the need to offer a competitive wage and benefits comparable to other job opportunities.

Q: Is this an effect of the pandemic, and do you see costs reducing in the future?

A: No, this is not a result of the pandemic. Workforce recruitment and retention issues have been on the rise before the start of the COVID-19 pandemic. The pandemic has not exacerbated the issue, but due to the complex nature of labor availability and desire to enter and stay in the industry, there is not an immediate fix, and I expect current and possibly increasing costs to continue into the future. However, while the labor workforce is not completely controllable by the Company, the Company has embarked on some initiatives in conjunction with our vendors to address the problem, raise the issue at a regional and a national level, and help provide a steady and qualified labor force for future work.

I initiated a regional workforce retention discussion where the issue was confirmed across 5 regional utilities. These utilities also commented on the increase of vegetation damaging storms and an increase in regional vegetation management initiatives and necessary workforce. I brought the matter to a national level through the Utility Arborist Association ("UAA") where similar concerns were raised, elevating the issue to the topic of focus for the UAA Vegetation Manager's Summit. The focus was on the workforce retention issue facing the utility line-clearance industry, the impact of utility practices on vendor workforce retention, and next steps to retain and attract workers. The formation of a UAA Workforce Retention and Recruitment Task force was formed and I am the current co-chair of the initiative. I am also involved in efforts led by American Forests, supported by grants, to create a tree worker pre-apprenticeship program aimed at worker recruitment and retention. Areas of opportunity and lessons learned from these efforts will be used to bolster the Company's program and combat the workforce issue.

Q: What other factors drive the VMP's costs?

A: Other field factors such as high tree density, high customer density per mile, overall forest health, scenic road designations, and traffic control / work protection requirements, all affect program costs in the Company's service territory when compared to other companies or locations.

<u>High Tree Density</u>

High tree density found in the service territory contributes to increased costs for all program components relative to similar components in land areas with lower tree density. The overall tree pruning and maintenance needs are higher when there are more trees per mile, resulting in increased costs. Not only are there more trees to prune per mile, but there are potentially more hazard trees to remove per mile. Increased pruning requirements also increase the volume and time required for wood debris and chip disposal. Further, with a higher number of trees per mile, the increased exposure of trees to electric overhead lines results in potential for increased customer requests and damage in storm events and the associated costs.

<u>High Customer Density</u>

Areas with high customer density per mile also contribute to increased costs for all program components relative to similar components in areas with lower customer densities. High customer density per mile necessitates increased customer outreach, which is typically time-consuming and costly. High customer exposure also results in higher customer awareness, and potential increased customer concern which could cause program restrictions on work originating from private property (i.e., outside the Company's right of way), increasing program costs.

Forest Health

The overall forest health of the service territory, with regard to tree and stand age, health, and maturity, as well as overall hazard tree population and mortality rate, has the potential to affect the costs for all program components. Poor forest health can be a factor of overall tree population aging, commonly found in New Hampshire where stands matured together after areas cleared for farming returned to forest. This can lead to an increased hazard tree population relative to other areas with a mixed stand age population. Another factor for poor forest health is the effect of damaging storm events and the residual health decline that occurs after many trees cannot recover from the extensive damage. The Company has seen an increasing trend of damaging storm events, resulting in ice damage, wind damage and heavy wet snow damage that has affected the forest health. Pest infestations, such as the highly destructive and invasive Emerald Ash Borer, as well as the Winter Moth, and the Hemlock Wooly Adelgid, all found in the Company's service territory, also have the potential to affect forest health and contribute to increased tree mortality. All of these factors affecting forest health - aging stand maturity, decline after damaging storm events, and pest infestation, lead to high hazard tree populations and increased costs to manage and reduce the risk from hazard tree and limb failure.

Importantly, the highly destructive and invasive Asian Longhorned Beetle present in the neighboring state of Massachusetts, is not currently affecting the Company's costs, but has the potential to impact costs substantially if discovered in the service territory.

Scenic Road Designations

Scenic roads and other municipality designations that impose restrictions, measures, or guidelines that must be followed for vegetation pruning and hazard tree removal contribute to increased costs for all program components. Scenic road planning, hearings, notifications, and permits add increased supervisory and administrative costs. This also requires the design, production and distribution of educational material and resources such as printed literature and web information sites. Restrictions imposed on obtaining authority for the necessary work also impacts costs as full program benefits are not realized and "hot spotting" or other work between pruning cycles therefore must be scheduled.

Traffic Control and Work Protection

Traffic control and work zone protection is a necessary part of vegetation management work completed along roadways. Program costs are affected by the requirement to use traffic control protection, specifically with the use of police officer details on the majority of streets in the Company's service territory. Estimated costs for traffic control are based on historic annual spend per work type. This cost is tracked separately from the individual program work types since the Company has limited control over police costs and requirements, which allows for an improved ability to measure actual cost of work for the individual program work types. Even though the Company has limited control over traffic control costs, it is a large factor in overall costs, and every effort is made through contract strategy, field practices, and oversight to minimize traffic control costs.

Q. Is management and implementation oversight necessary to minimize the vegetation management program's costs?

A. Yes. Management and work implementation oversight is a critical component to keeping costs minimized and to maximizing cost savings. Effective management planning "streamlines" implementation and eliminates time loss and duplication of effort. Direct oversight of field work and field communication minimizes down time, keeps productivity high and engages workers in striving toward Company goals and targets, which all work to boost efficiencies and effectiveness.

IV. STORM RESILIENCY PROGRAM

A. OVERVIEW, DEVELOPMENT AND STRATEGY

Q. Is UES proposing the continuation of the SRP?

A. Yes. The Company is proposing the continuation of the SRP, which is a companion or complementary program to the VMP. The SRP is different in that it is aimed at reducing tree exposure along critical sections of select circuits in order to improve performance during major storm events. The goal of this program is to reduce tree-related incidents, resulting customer interruptions, and more significantly, municipality impact along critical portions of targeted lines in minor and major weather events. In turn, the Company aims to reduce the overall cost of storm preparation and response, improve restoration, and preserve municipal critical infrastructure for the purpose of enhancing public health and safety.

Q. What is the history behind this program and its importance?

A. In 2011, the Company experienced two large weather events that affected its service territory: Hurricane Irene, and the October Snowstorm, where over two feet of snowfall was recorded in New Hampshire. The 2011 October Snowstorm caused widespread damage and prolonged outages and was the second largest event in the Company's history. In 2012, the Company was hit by Hurricane Sandy. Prior to 2011, the Company had also sustained other frequent major storm events over the previous four years.

As a consequence of the type of damage experienced and the length and cost of restoration efforts, the Company began to explore the options available to "harden" or make critical elements of the system more resilient to storms. After a review of different options available, such as undergrounding electric lines, and reviewing rough cost estimates, the Company recognized that there was an opportunity to implement a vegetation-centered storm hardening program which would provide many of the expected benefits at a much lesser cost than alternatives.

Q. What is the scope of work related to this program?

A. The scope of work for the SRP is for critical three-phase sections of select circuits, defined as the circuitry from the substation out to a desired protection device, to undergo tree exposure reduction by: (i) removing <u>all</u> overhanging vegetation, or pruning "ground to sky;" and (ii) performing intensive hazard tree review and removal. In addition, under the SRP the remaining three phase circuitry beyond the designated critical portions receive hazard tree review and removal. The scope of work also takes into account critical infrastructure needs for the towns and cities affected. The locations of police and fire departments, schools, emergency shelters and other critical business centers are considered along with the critical electric infrastructure.

Q. How does this program differ from the VMP?

A. The SRP differs from the VMP in that it targets areas that are outside of the VMP's scope. The current VMP is designed to be effective for normal conditions and weather events, described as up to 50-60 mph winds, where the failure of defective trees and limbs predominates. The storm resiliency program involves the removal of *all* tree exposure to the lines, affecting non-actionable and non-defective tree failure that begins to predominate above 50 mph winds. The difference between maintenance pruning and reduction of exposure can be seen by looking at: 1) the pruning specifications for the cycle pruning program versus the storm resiliency program; and 2) the intensity of hazard tree removal on the hazard tree mitigation program versus the storm resiliency program.

Cycle pruning specifications are to prune vegetation away from the conductors to a height of only 15 feet above, 10 feet to the side and 10 feet below. Such clearing is adequate for normal conditions. The storm resiliency program specifications, however, are to remove <u>all</u> overhanging branches and limbs from above the conductors and out 10 feet to the side.

The difference in intensity between the hazard tree mitigation program and the removal of hazard trees under the storm resiliency program can be broken down into two components: 1) the actual tree populations inspected for each program; and 2) the risk accepted, or the level of defect found on inspection that actually warrants tree removal.

First, hazard tree removal under the hazard tree mitigation program component is governed by risk as described in the tree risk management protocol. Under this protocol, risk is assessed based on a specific population of trees only as defined by the location on the circuit and the corresponding customer damage category. The tree inspections performed are focused on the tree population on the same side of the street as the pole line, as the Company assumes less risk due to their proximity to the pole lines, and a limited visual assessment of the opposite side of the street from the pole line. These surveys are predominantly performed from a vehicle. In many cases only limited danger trees (when specified defects or tree health problems are observed) are inspected. In the SRP, all trees capable of interfering with the safe, reliable transmission of electricity upon failure are inspected. Tree inspections performed under the SRP are walking surveys of the tree population, including 360 degree examinations around the electric facilities, which includes tree populations on the opposite side of the street from the pole line.

Second, the level of risk accepted on the hazard tree mitigation program is higher than that of the SRP. Trees showing inspection defect(s) with a likelihood of failure of "imminent" and "probable with a modifier" are removed in customer damage categories of high and moderate. This is adequate for normal weather conditions. For the SRP, trees with a likelihood of failure of "imminent," "probable with a modifier," as well as those with a likelihood of "probable," "possible with a modifier," and "possible" are removed. Again, this level of clearing is designed for major storm events.

Q. How did the Company decide which circuits should be included in the SRP?

A. The Company reviewed all circuits individually for inclusion in the SRP. In order to be effective, certain criteria such as tree field conditions and customers served on a circuit were deemed to be significant. Criteria for the program included: 1) tree-related field condition; 2) customer count; 3) circuit total miles of three-phase; and 4) presence of scenic roads or other vegetation restrictions. Any circuits that were located primarily in low tree density areas, without critical municipality needs, were removed from the program circuit list. Any circuits with less than 500 customers served were reviewed for need as well as any circuit with less than two miles of three-phase line. Areas designated as scenic roads or with other known restrictions were also removed from the program.

Q. Was this program implemented in previous years?

A. Yes. This program was implemented as a pilot in 2012 and 2013, then transitioned to a full program in 2014. Over the past nine years of SRP work, 39 circuits along 284.3 miles of line were mitigated, serving 51,337 customers and numerous life line, life safety and community resources including schools, community emergency shelters, and hospitals. Over 20,600 risk trees were removed.

Each year, implementation began with an outreach program, where the municipalities were notified of the intent, scope of work, and given a tentative schedule. A trained work planner identified work to be performed, conducted extensive customer outreach and education related to the program, and sought tree owner consent for pruning and removal. Over these nine years, overall customer understanding and acceptance of the program was very high.

Tree pruning and removal work began in the final quarter of each year and continued through the end of the fiscal year. The use of specialized equipment such as cranes, and log loaders along with staged wood removal sites was employed to reduce the surrounding vegetation impact and overall appearance to the community.

Each year, the program wraps up with tree removal replacements offered to customers that underwent significant tree pruning or removal activity. Overall, customers were pleased with the work and the replacement trees which fit the "right tree, right place" goal for compatible trees adjacent to the overhead electric lines.

Q: What work is remaining from the initial SRP proposal?

A: There are two years remaining in the initial SRP proposal work plan. This year's work of 37.6 miles is described in the Company's annual VMP filing DE 20-183. Approximately 26 miles is scheduled to be done in calendar year 2022.

Q. Has a similar program been implemented anywhere else?

A. Yes. The Company's affiliate, FG&E has implemented a successful SRP in its Massachusetts service territory since 2014.

B. WORK PERFORMED, COSTS, AND BENEFITS

Q. What were the costs of the SRP for the test year?

A. As indicated in the testimony of Messrs. Goulding and Nawazelski, the costs for the 2020 storm resiliency program were $1,439,617[1], slightly above the estimated 2020 budget of $1,423,000.

Q. What are the expected costs of completing the work for the remaining two years of the initial proposed SRP?

A. The Company expects the costs of the SRP to be $2,931,380 to complete the approximately 63.6 miles of qualifying overhead, three-phase lines identified through the initial project scope. Due to the varying nature of storm resiliency work and traffic control, the Company experience minor variances, with final annual costs being slightly above or below the estimated budget. The Company believes that $1,465,690 (equal to the current annual program funding level of $1,423,000 plus 3% inflation, driven by recent increase in labor costs) is an appropriate and reasonable estimate of the Company's targeted spending for its SRP in 2021.

Q. Are there additional factors that can affect cost?

A. Yes. There are some variable factors that can affect cost. The actual hazard tree population and number of removals necessary along the program area will vary, which would affect cost to implement the work. Customer and municipal acceptance of desired work can affect the number of trees pruned and/or removed. Other ongoing

[1] Messrs. Goulding and Nawazelski Schedule RevReq-3-3, Column 2 Line 13.

work on neighboring utilities' systems could affect the level of third party resources available to complete the work and the bidding vendor pool, thus affecting cost.

Q. How will these variable factors be minimized?

A. These variable factors will be minimized through extensive planning as well as field and management oversight. Hazard trees to be removed will be prioritized according to risk. The Company will engage in extensive interaction and advance notice to towns and the use of a specialized trained company representative for customer education and consent, and to promote the acceptance of the work. Advance planning and notice to a large vendor pool and timing of project and bid release will be used to minimize cost changes associated with competing work.

Q. What are the desired benefits of implementing the SRP?

A. The desired benefits of the SRP are, at the core level, improved reliability, improved customer service and satisfaction, reduced safety risks, and avoided costs during storm events. These benefits are seen by the prevention of tree-related failures and subsequent electric incidents. This reduction in incidents reduces damage to the electric infrastructure and the need for crews to respond, in turn reducing overall storm restoration costs. More information on the expected benefits of the SRP can be found in my testimony for the 2016 rate case, excerpt attached as Exhibit SMS-2.

Q. Have any measurable benefits been realized since the implementation of the SRP work in 2012?

A. Yes, the Company has had instances of storms and foul weather over the last 9 years to put the SRP to the test. As explained in the previous 2016 rate case, DE 16-384, the Company has found favorable results by examining tree failures in major storms. The results indicate appropriate field identification of risk trees, avoided interruptions and costs, and positive public acceptance.[2] In addition to this data, the Company wanted to analyze the results of the program in more depth. In order to do that, the Company brought in a team of consultants to build and implement an analysis tool that could process the large amount of data from multiple sources and accurately compare areas of non-SRP work to areas of SRP work. The tool was then used to do an independent analysis of the Company's SRP program. The full report titled "Storm Resiliency Program Analysis and Assessment" prepared by Environmental Consultants (ECI) is attached as Exhibit SMS-3.

The analysis used vegetation management work data, outage management data, and customer calls mapped spatially using the geographical information system, LiDAR and imagery. By comparing circuit performance for areas of non-SRP to areas of SRP, the assessment found the following:

> *The six trend graphs show a clear improvement trend in SRP circuit performance for SAIDI, SAIFI, and CAIDI as compared to the non-SRP circuit performance. The increase seen in Outages by Year for all phases are due to increases in tree-caused outages (including increased weather-related events) on the single-phase portion of the circuits that were not maintained as part of the SRP program. The largest improvements in SRP circuit performance can be seen in the graphs for three-phase only performance (Figure 12) particularly during storm events (Figure 14).*[3]

[2] Additional information can be found in an excerpt of 2016 rate case DE 16-384 attached as Exhibit SMS-2

[3] Quote from page 12 of 22 of Exhibit SMS-3 – Environmental Consultants "Storm Resiliency Program Analysis and Assessment"

In addition, using storm financials and the Interruption Cost Estimate (ICE) calculator, the analysis found that there is significant total external and internal cost avoided by implementing the full SRP program, estimated to be between $6.46M and $17.87M per year with the net cost avoided after funding the SRP program to be between $4.58M and $15.99M per year.[4]

Q. Has the Company drawn conclusions about the benefit of a storm resiliency program?

A. Yes. After reviewing the results of the storm resiliency initiatives implemented in New Hampshire and Massachusetts, the Company concluded that the reliability effects, the avoided interruptions and costs, the positive public acceptance, and the benefits to customers are significant benefits that more than offset the cost to implement. As demonstrated by the results of the ECI Assessment and the Company's performance in storm events, this program brings savings to customers through future avoided storm costs, and many additional and important public health and safety benefits. For this reason, the Company is proposing the continuation of the vegetation management SRP.

C. CONTINUED PERFORMANCE AND NEXT STEPS

Q. Is the Company proposing continuation of additional SRP after the conclusion of the initial proposed program?

A. Yes. The Company is proposing to continue SRP efforts past the conclusion of the initial program in 2022. This next cycle of SRP work will be aimed at revisiting circuits done in the first cycle, performing work on any sections that may have been

[4] Exhibit SMS-3 - Environmental Consultants "Storm Resiliency Program Analysis and Assessment", Page 20

added due to circuit reconfiguration or construction, and also extending SRP work out further on circuits where appropriate. In addition to reviewing the same circuits that were done 10 years ago, the Company's new storm resiliency analysis dashboard allows for performance tracking and can be used to identify poor performance, worsening conditions, and areas that need additional work.

Q. Why is this next cycle important?

A. It is important to revisit the circuits that underwent SRP work in the first cycle to ensure that these circuits continue to be resilient during storm events and that the investment made toward this effort is not diminished and ultimately lost. This next cycle will bolster these circuits toward the goal of continued improved performance for an additional cycle. During the 11 years that elapse from the first cycle to the second cycle, many field conditions can change and trees that were assessed during the first cycle and found to pose a low risk, may now have declined and pose a higher risk. There was a significant initial investment made which produced results making the system more resilient; the need to maintain that investment in order to continue receiving the benefits is critical. In addition, the Company can build upon the initial investment and add further benefit with additional work on poor performing circuits or circuit segments and extension of work sections farther out on a circuit.

Q. What funding do you expect to be necessary to implement this next phase of SRP?

A. The Company expects the next cycle of SRP, beginning in 2023, to require some reallocation of funding. It is expected that the next cycle will have less ground-to-sky maintenance pruning as part of the SRP scope, as that clearance has already been obtained 11 years prior, and the pruning cost associated with maintaining that initially cleared ground-to-sky work will be borne as part of the cycle pruning maintenance activity instead. Through estimation of the vendor costs for the past cycle, it was estimated that approximately 20% of the cost per mile of SRP would transfer to cycle pruning in 2023. Using the projected cost per mile in 2021 of $38,981 per mile and the 34.65 miles planned in 2023, this calculates to approximately $1,081,000 for SRP per year. The remaining $384,690 is expected to be required to cover the increase in cycle pruning and would be reallocated to this line item after the initial SRP cycle concludes in 2022.

Q. Could storm performance and reliability suffer if the SRP is not continued?

A. Yes, storm performance and reliability could suffer if the SRP is not continued. Customers have seen avoided minutes of interruption due to the SRP program, calculated at approximately 567,000 customer minutes of interruption ("CMI") savings through 2019 and estimated at being approximately 1.6 million CMI through 2022.[5] Each year that the SRP lines are not maintained and risk vegetation develops along the lines, the likelihood of tree related vegetation damage occurrence on the SRP portion of lines increases. Instead of avoiding 1.6 million CMI each year that number will diminish and customers will see more minutes of interruption for each storm event.

Q. Could customers incur additional costs if the SRP is not continued?

[5] Exhibit SMS-3 - Environmental Consultants "Storm Resiliency Program Analysis and Assessment", Page 10

A. Yes, since customers could see an increase in minutes of interruption, the customer interruption cost, or the economic cost that customers incur when they experience an interruption in electricity service, would also increase. If all of the calculated expected reliability improvement of the SRP program diminishes, the annual customer cost avoided which is estimated between $5.44 million and $16.85 million[6] would be lost and customers would instead experience the economic cost of those interruptions.

Q. Does this conclude your testimony?

A. Yes, it does.

[6] Exhibit SMS-3 - Environmental Consultants "Storm Resiliency Program Analysis and Assessment", Page 20

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY OF

SARA M. SANKOWICH

New Hampshire Public Utilities Commission

Docket No. 16-384

A. These variable factors will be minimized through extensive planning as well as field and management oversight. Hazard trees to be removed will be prioritized according to risk. The Company will engage in extensive interaction and advance notice to towns and the use of a specialized trained company representative for customer education and consent, and to promote the acceptance of the work. Advance planning and notice to a large vendor pool and timing of project and bid release will be used to minimize cost changes associated with competing work.

Q. Have any measurable benefits been realized since the implementation of the SRP work in 2012?

A. During the course of the initial pilot pruning and removal work in 2012, the Company was faced with a unique situation to test the work's response to a storm event. On October 29, 2012 Hurricane or "Super Storm" Sandy came up the east coast and affected the Company's New Hampshire service territory. At this time, one of the three storm pilot circuits was in the final stages of completion. Only a few customer tree removal negotiations and pruning spots remained. On the second circuit, pruning and removal was just beginning, and work had not started on the third circuit. This left the unique opportunity to study the effects on the worked and unworked circuits during one event. As rain and wind from Hurricane Sandy pelted the Seacoast area, the first circuit that had work completed held up remarkably well. The main line of the circuit experienced no events and many of the customers fed off this circuit did not experience a single interruption. A customer communication after the storm event, shown below, is representative of many emails, phone calls and Twitter "tweets" UES received and the customer experience during this storm event:

Just wanted to let you know how wonderful it was not to lose power during the hurricane. I believe it was directly attributable to all the tree cutting and trimming Unitil did especially in the Pollard Road and Westville Road area. My husband and I had our home built here thirty seven years ago....this is the first big storm that I can remember that power remained on!! I know there is no assurance this will be the norm but I think you all are striving hard to make it that way. Thanks so much!! -Plaistow, NH

There was one tree-related event in the storm pilot area along the first circuit where a desired tree removal, still in discussion with an unsure homeowner, failed and contacted the phases. However, the tree was removed during the storm and those customers affected were restored quickly. The customers on this circuit experienced many of the benefits expected from the SRP.

The other two Storm Pilot circuits that had not had tree removal started faced more tree-related incidents and the main line of both of these circuits experienced tree-related troubles which led to substation lock-outs, longer outages for a larger number of customers in the area, and increased time and manpower to restore. I performed a field review directly after the storm event which demonstrated multiple tree failures along the Storm Pilot designated area. Two sideline tree failures on the mainline of the second circuit had been marked and approved for removal prior to the storm, but had not yet been removed. Had these removals been done prior to the storm event, associated reliability loss, damage, and cost would likely have been prevented.

In 2014 the Company was again able to test the SRP. On Wednesday November 27 through Thursday November 28, 2014 the Company's Capital region in New Hampshire experienced a heavy wet snow event that was forecasted as an EII 3 event with snow totals over 10 inches. During this event, the electric system experienced significant damage. However, there were limited tree related damage events on the portions that underwent storm resiliency work in 2013. To document and analyze the performance of these circuits, the Company employed a vendor to record vehicle mounted high definition video during restoration portions of the storm, after snowfall was completed. The video captures analysis and performance of the circuits and can be viewed in a Company's short film titled "SRP Video 2014,".

Q. Other than the benefits described above, are there any reliability improvements attributed to the SRP?

A. The Company has seen an overall reliability improvement related to tree-related outages over the past five years, as shown in Schedule SMS-1. While the Company would like to attribute this in large part to the SRP, it is difficult to distinguish this result from a number of other factors such as the vegetation management program, capital improvements, emergency response plan, and favorable weather conditions.

Q. What are the expected benefits of implementing the SRP?

A. The expected benefits of the SRP are, at the core level, improved reliability, improved customer service and satisfaction, reduced safety risks, and avoided costs during storm events. These benefits should be seen by the expected prevention of tree-related failures and subsequent electric incidents. This reduction in incidents reduces damage to the electric infrastructure and the need for crews to respond, in turn reducing overall storm restoration costs.

There are also more specific benefits, which drive the core benefits, expected from implementing the SRP. These include:

- Preserving municipal critical infrastructure
- Minimizing the dependence on mutual aid and off system resources
- Minimizing the total number of resources required to restore service
- Shortening the duration of major events
- Minimizing the overall cost of restoration
- Reducing economic loss to municipals, businesses, and customers
- Most cost-effective solution vs. other alternatives

Because of the design of the SRP, much of a municipality's critical infrastructure is included in the targeted circuitry. These areas are also most often the business centers for the municipality, and therefore include gas stations, restaurants and hotels. Preserving power during multiple-day events to both municipal infrastructure and business districts ensures functioning emergency service, and a place where residents can seek temporary warmth and shelter.

In addition, many states and regulatory jurisdictions have established standards for restoring power during major events, the competition for securing outside line resources has increased significantly and, as a result, resources have become both scarce and very expensive. Often, in order to secure an adequate amount of resources for a particular event, the Company has been required to reach outside of the New England area, adding travel time and additional cost. One way, however, to mitigate these escalating costs is to prevent the damage from occurring in the first place. Less damage translates into a reduced need for outside crews, which, in turn, lowers overall costs and shortens the duration of an event.

As electric utilities review various options to improve overall storm performance, the undergrounding of utility infrastructure is often mentioned, but quickly dismissed due to significant cost and impracticality. Implementation of an SRP may achieve similar performance to that of undergrounding at a fraction of the cost.

Municipalities and businesses have described the significant economic impact of losing power for multiple days. These natural disasters are very disruptive, result in a loss of business income and tax revenue, personal income loss, and increased costs to municipalities due to the requirements of providing emergency services, debris removal, and requiring overtime work for multiple departments. Any actions that help to minimize this disruption will provide some measure of economic relief.

Finally, customers have expressed concern with losing power for multiple days. Although it is impossible to prevent storm damage across the entire system, preserving power and minimizing damage for each municipality along its main business corridor as well as protecting its emergency critical infrastructure appears to offer significant promise as a means to assure safety and provide some measure of security during and after these extreme weather events.

Q. Has the Company drawn conclusions about the benefit of a storm resiliency program?

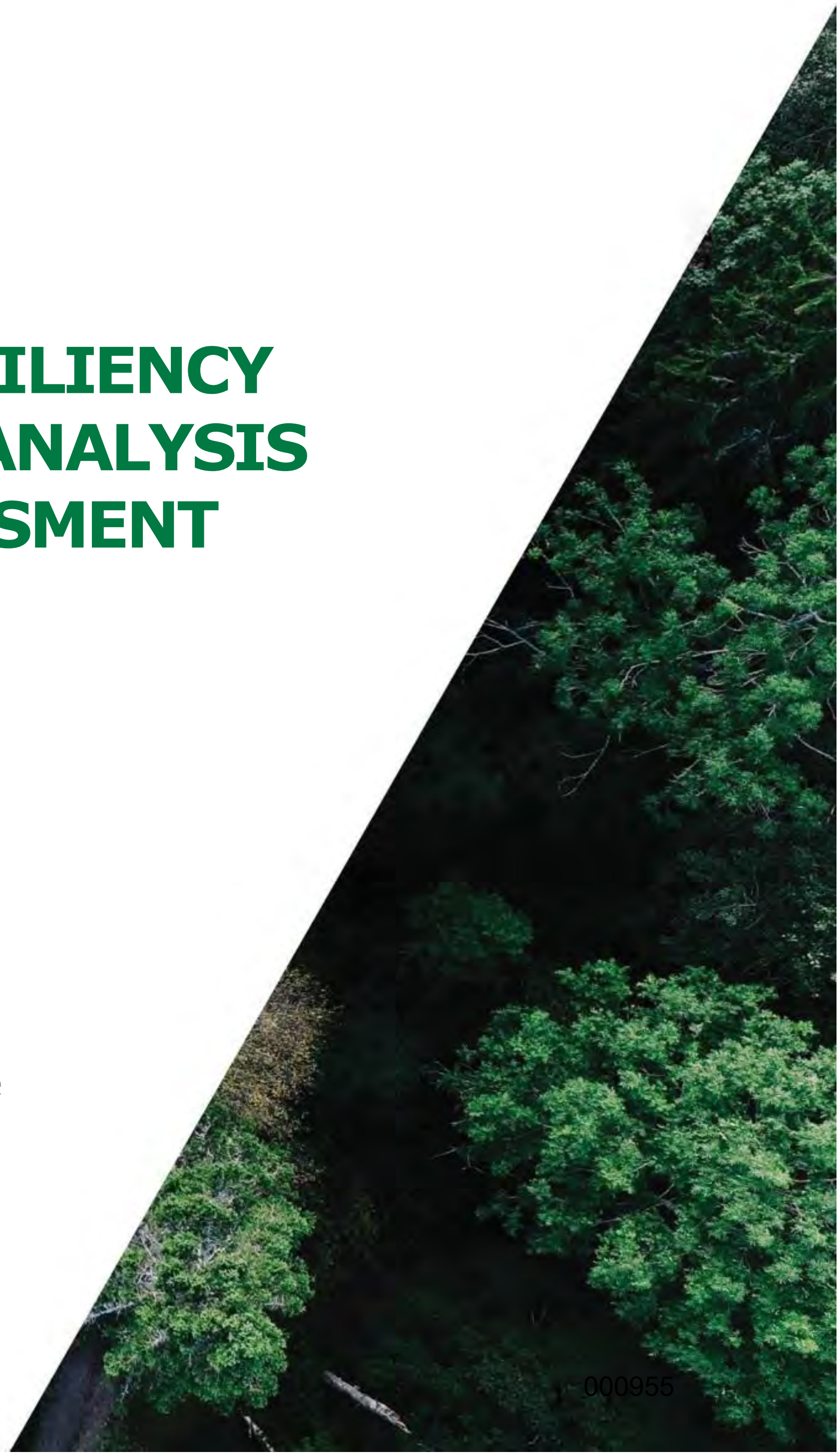
A. Yes. After reviewing the results of the storm hardening initiatives implemented in New Hampshire and Massachusetts, the Company concluded that the reliability effects, the

Environmental Consultants

STORM RESILIENCY PROGRAM ANALYSIS AND ASSESSMENT

Prepared for:

Unitil
energy for life



SUBMITTED BY
Lakeside Environmental Consultants, LLC
D.B.A. Environmental Consultants (ECI)

12324 Hampton Way Dr.
Suite 104
Wake Forest, NC 27587
United States of America

August 3, 2020

Table of Contents

1.0 OVERVIEW

Unitil Corporation provides electric and gas operations in Maine, New Hampshire and Massachusetts, serving approximately 106,000 electric customers and 83,600 natural gas customers. Following Hurricane Sandy in 2012, which devastated large portions of the Northeast, Unitil was faced with restoring power to 69,000 electric customers.

In response to requests from customers and municipalities to improve service reliability and harden its electrical infrastructure against future storm events, Until Corporation developed a 10-year Storm Resiliency Program (SRP) to prevent power outages caused by trees and adjacent vegetation. The program's intent is to make the electric system more resilient to tree outages particularly during storm events. To accomplish this, Unitil sought ground-to-sky clearance to include the removal of trees and branches growing above electric wires, and incompatible trees growing underneath them.

The stated goals of the SRP fund as defined in the Electric Reconciliation Mechanism Filing in MA DPU 18-149 and NH DE 16-384 are as follows:

- reduce tree-related incidents and resulting customer interruptions;
- reduce municipality impact along critical portions of targeted lines in minor and major events;
- reduce overall cost of storm prep and response;
- improve restoration; and
- preserve municipal critical infrastructure.

To help quantify the impact of the Storm Resiliency Program, Unitil engaged GeoDigital in 2016 to utilize LiDAR data to assess the before trimming SRP condition and the after trimming SRP conditions of circuits maintained under this program. In 2019, Unitil requested an addition SRP Assessment utilizing the captured LiDAR data to focus on measuring the system reliability improvements and overall performance resulting from the Storm Resiliency Program, including the costs and benefits of Unitil's strategy to proactively identify and remove vegetation risk. To complete the assessment, Unitil engaged Environmental Consultants, LLC (d.b.a., ECI) as the lead consultant with OBI Partners providing operational reliability intelligence and data analysis.

2.0 ANALYSIS

The analysis focused on identifying and isolating where outage events occurred on circuits included in the SRP Program. This effort included the review of outages pre- and post-SRP completion. Outages were correlated to the available LiDAR data to identify vegetation conditions on the fault device to determine a more precise outage location to ensure proper alignment with SRP and non-SRP line sections. From this analysis, the impact of SAIDI and CAIDI for the Storm Resiliency Program could be estimated.

The following report discusses the process, results, and recommendations from ECI, and in part, leverages data derived by OBI Partners' performance analysis.

2.1 Utilizing Reporting Dashboards

Several standard reports and dashboard elements from OBI Partners Outage Management, Storm Management, and Vegetation Management solutions were used as a basis of the work for this analysis. Several of those components and their relationship can be seen in Figure 1.

The analysis tool was populated with Unitil's data to support this analysis effort. In addition to providing an information framework for this analysis effort, the platform was designed to be configured for automated updates and used for additional analysis, performance monitoring, and follow-up work initiation.

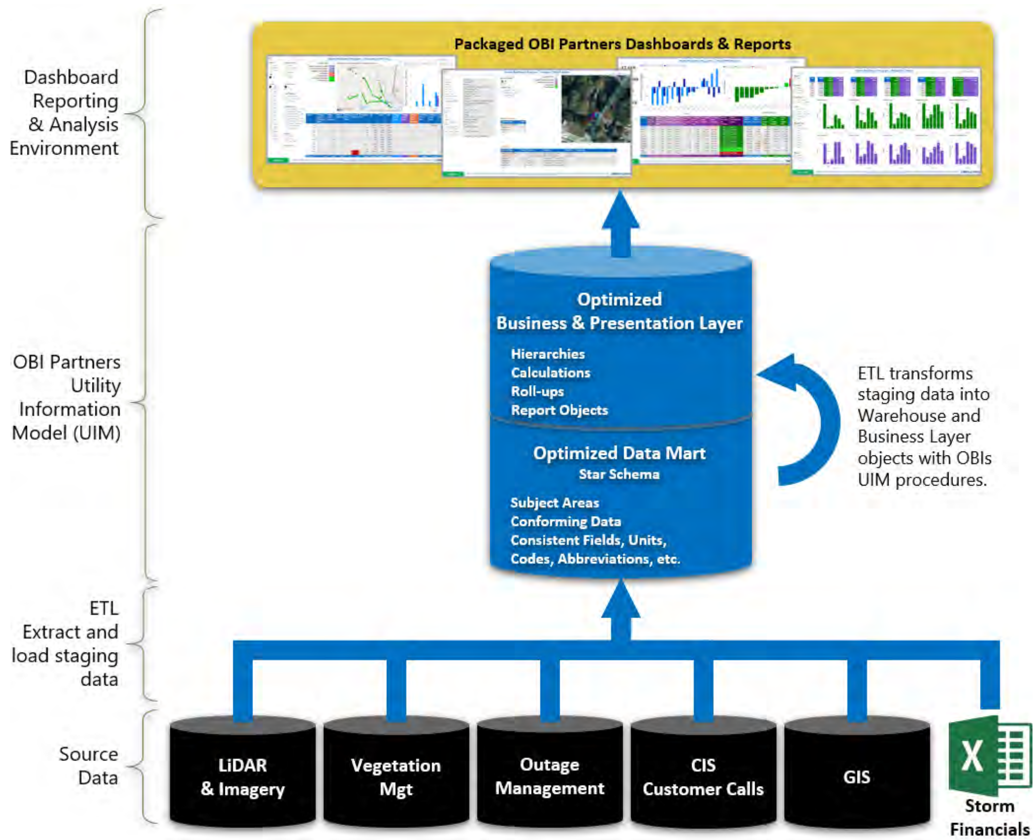


Figure 1 - OBI Partners - Utility Information Model Solution Overview

The platform standardized data via an Optimized Data Mart focusing on:

- Conforming data from disparate sources
- Standardizing data nomenclature and formats across the disparate sources
- Providing a single source of the truth
- Supporting machine data analytics
- Insulating the reporting environment from changes to source data and applications

The platform allowed Reporting and Analysis via an Optimized Business Layer by:

- Preparing data for users to support a broader range of technical skills and improve productivity
- Providing advanced calculations and roll-ups for reporting
- Simplifying the data environment for report builders and data analysts

2.2 Isolating Outage Events on SRP Circuits

Outage events were correlated to SRP Program circuits both spatially and temporally. This identified outages that occurred where SRP work was performed, and whether those outages occurred before or after the SRP work was completed. The figures below illustrate one selected circuit. Figure 2 shows outage events that occurred before SRP work was complete on the circuit. The symbology identifies those that are spatially related to where work was eventually completed and those that were not. Figure 3 shows outages that occurred after SRP work was complete along with SRP work locations.

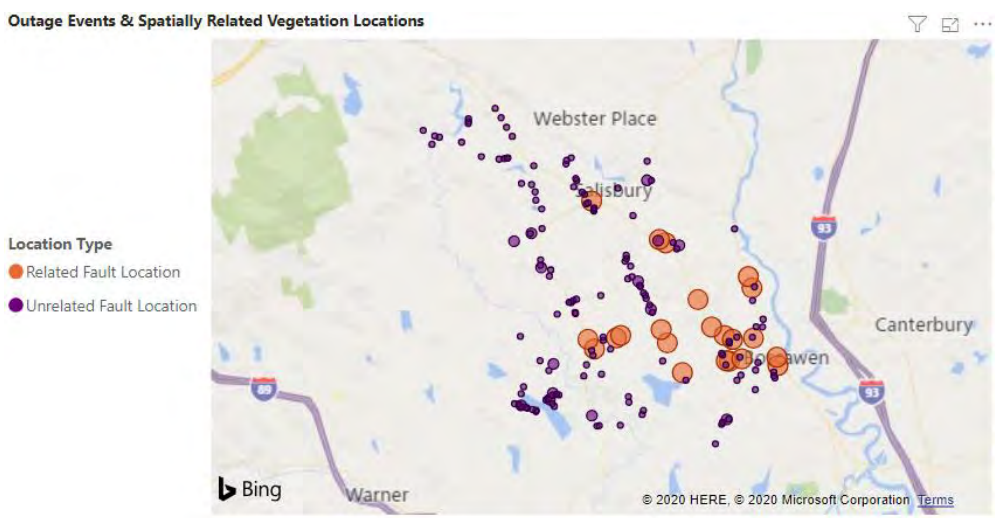


Figure 2- Outage Events Prior to Work Completion

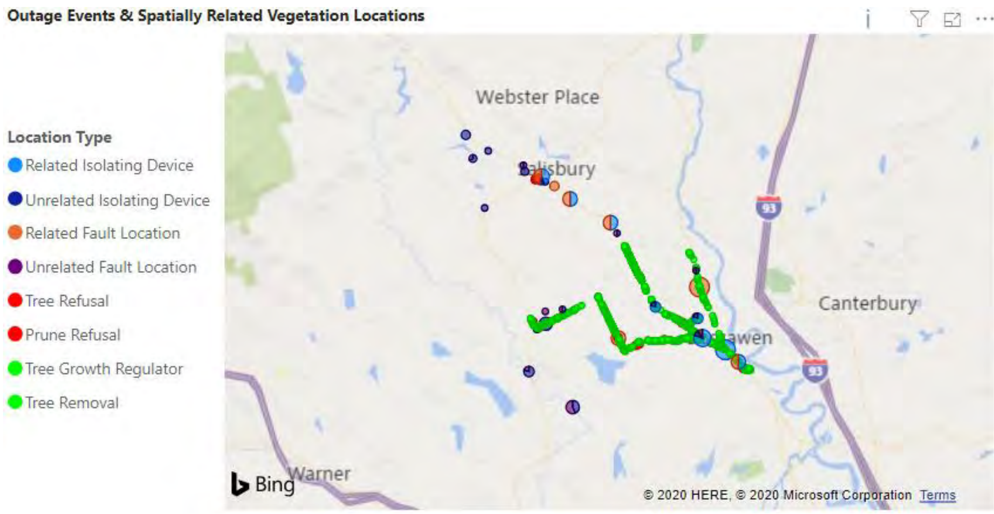


Figure 3- Outage Events After Work Completion

From a more detailed perspective, Figure 4 shows an individual outage fault location on this circuit, along with related SRP work locations. For the purposes of this analysis, to be related, those work locations had to be both; within a specific proximity and occur after work had been completed.

Figure 4- Single Event Fault Location and Associated SRP Work Locations

The example above identifies three *Tree Removal* work locations and five *Tree Refusal* locations. These work activities occurred before the outage event, and because *Tree Refusals* existed in the immediate area of the fault location the outage was discounted from any outages that occurred in the work zone following SRP work. These outages were removed from the circuit performance data following SRP completion to avoid skewing circuit performance with non-preventable outage data.

2.3 Isolating Circuit Performance Both Before and After SRP

As mentioned in Section 2.2 above, the study identified all events that occurred before and after SRP work completion. Where data was available, the study looked at circuit performance from 2014 leading up to SRP, and the maximum number of years after SRP work was completed.

The data provided by Unitil included:

- Outages from 2014 through 2019
- SRP circuit work locations from 2015 through 2019 with sparse records for 2013 & 2014
- Storm data including storm name, storm timeframe, and storm costs for 2014 through 2019
- Other associated data such as; Poles and their locations from GIS, and Customers Calls, that were used along with the Outage and Work Location data.

Circuit performance using CMI, SAIDI, SAIFI, CAIDI, etc., was calculated for all circuits showing values and trends for SRP and Non-SRP circuits. Figure 5 shows results for all circuits.

Year	Events	CI	CMI	CMI/Event	SAIDI	SAIFI	CAIDI	Storm Events	Non-Storm Events	Storm CI	Non-Storm CI	Storm CMI	Non-Storm CMI	Storm CMI/Event	Non-Storm CMI/Event	Storm SAIDI	Non-Storm SAIDI	Storm SAIFI	Non-Storm SAIFI	Storm CAIDI	Non-Storm CAIDI
2014	989	146,679	51,651,912	52,226	482.23	1.37	352.14	202	787	58,365	88,314	28,390,034	23,261,878	140,544.72	29,557.66	265.05	217.18	0.5449	0.82	486.42	263.40
2015	414	54,040	4,030,715	9,736	37.63	0.50	74.59	39	375	6,629	47,411	530,285	3,500,430	13,597.05	9,334.48	4.95	32.68	0.0619	0.44	79.99	73.83
2016	600	55,161	8,653,598	14,423	80.79	0.51	156.88	175	425	30,862	24,299	6,624,725	2,028,873	37,855.57	4,773.82	61.85	18.94	0.2881	0.23	214.66	83.50
2017	966	146,244	40,088,479	41,499	374.27	1.37	274.12	408	558	92,453	53,791	34,190,638	5,897,841	83,800.58	10,569.61	319.21	55.06	0.8632	0.50	369.82	109.64
2018	1,061	123,830	35,632,465	33,584	332.67	1.16	287.75	299	762	56,331	67,499	25,012,156	10,620,309	83,652.70	13,937.41	233.52	99.15	0.5259	0.63	444.02	157.34
2019	715	61,026	12,573,404	17,585	117.39	0.57	206.03	364	351	26,369	34,657	8,473,167	4,100,237	23,277.93	11,681.59	79.11	38.28	0.2462	0.32	321.33	118.31

Figure 5 – SAIDI Performance Comparison – SRP and Non-SRP circuits

2.4 Evaluating Vegetation Condition Correlated with Outages

Fault locations related to SRP work were identified using outage detail data, including crew and dispatcher comments as well as customer call-in data. For the purposes of comparing circuit performance pre- and post-SRP work, it is crucial to only include those faults that were directly actionable by the SRP maintenance process. As such, faults that could be associated with customer refusals were excluded in the post-SRP analysis.

As with Figure 4 in Section 2.2 above, Figure 6 presents an additional outage example that occurred after SRP work was performed. The example shows several locations where *Tree Removals* occurred. The outage detail shows the outage occurred 11 months after the work was completed with no refusals or other impediments preventing SRP completion. Unlike the example in Figure 4, this outage did factor into post-SRP reliability metrics for the related circuit.

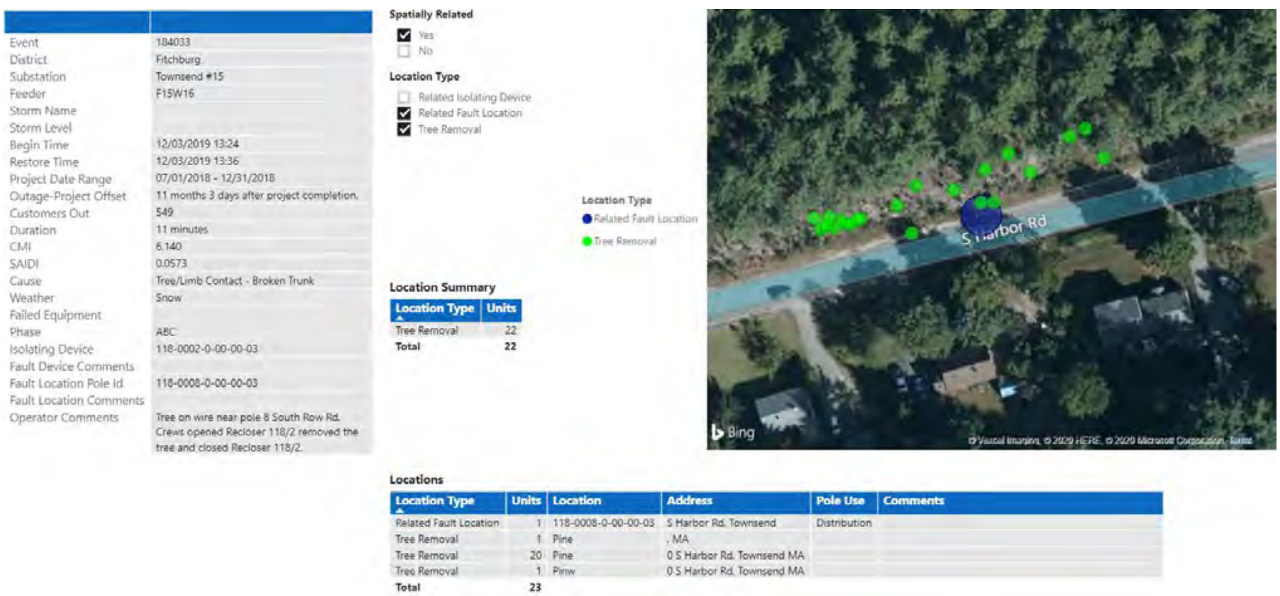


Figure 6 - Outage related to Tree Removals

2.5 Calculating SAIDI and CAIDI for the Storm Resiliency Program

SAIDI, SAIFI and CAIDI were calculated for the total SRP circuits and presented in Figure 7 and compared to pre- and post- SRP work. Additional metrics were defined and calculated to arrive at a circuit performance metric and projected reliability improvement. As illustrated in Figure 7, there is a clear improvement across the board for SRP completed circuits as compared to the circuits previous performance that positively affected the entire electrical network.

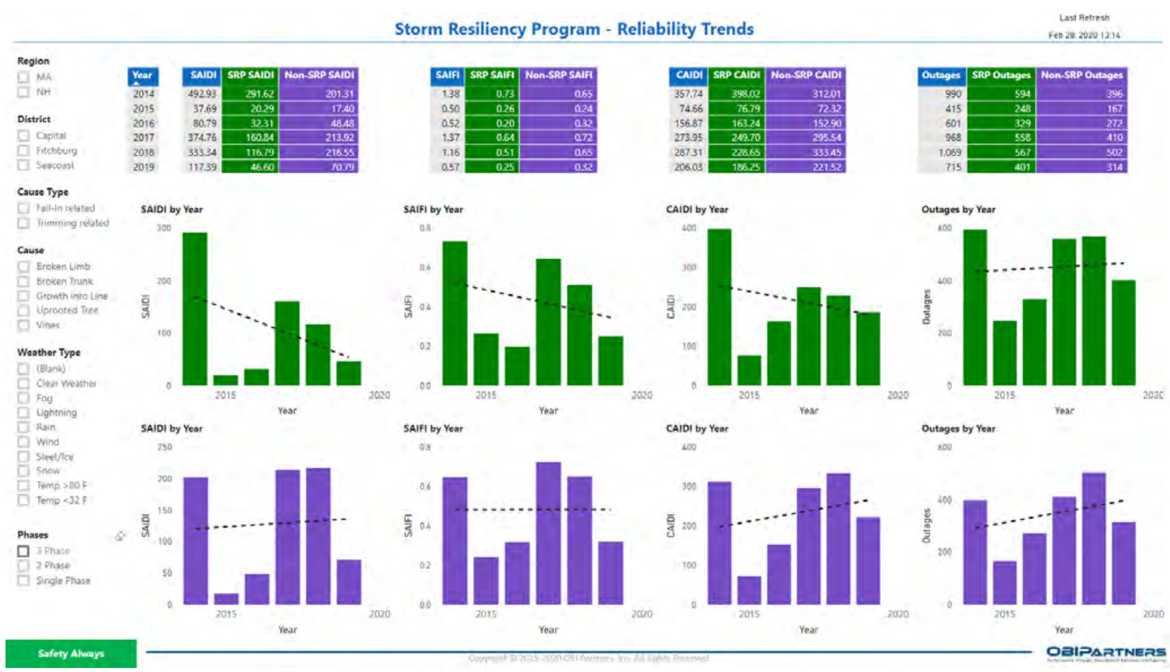
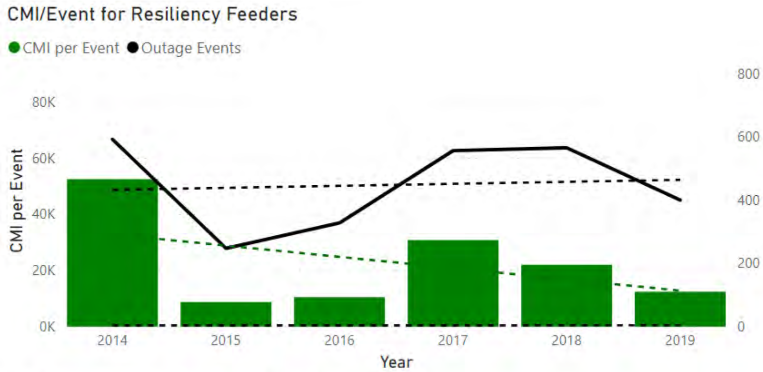


Figure 7 - SAIDI, SAIFI, CAIDI for SRP and Non-SRP circuits

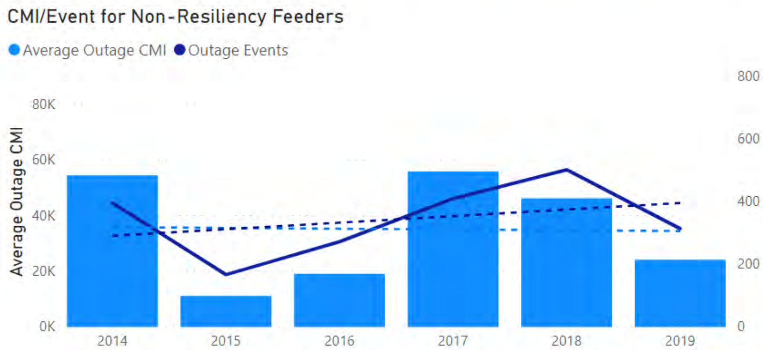
2.6 Additional Metrics used to determine SRP Performance

In addition to SAIDI, SAIFI and CAIDI, additional metrics were defined to get a further view of the results and impact of the SRP program. A Normalized CMI or CMI/Event analysis was performed to provide insight in the reduction of large main line events that may have hid multiple events occurring on laterals and services. From the charts below, SRP circuits had far lower CMI per event ratios than non-SRP circuits.



Resiliency Feeders

Year	CMI per Event	Events
2014	52,585	594
2015	8,765	248
2016	10,519	329
2017	30,873	558
2018	22,062	567
2019	12,447	401
Total	**26,547**	**2,697**



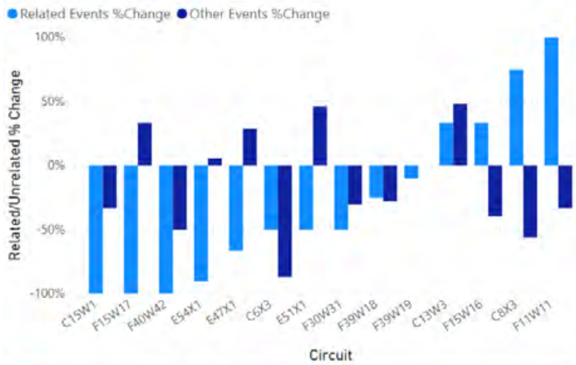
Non-Resiliency Feeders

Year	CMI per Event	Events
2014	54,452	396
2015	11,159	167
2016	19,092	272
2017	55,886	410
2018	46,204	502
2019	24,147	314
Total	**39,937**	**2,061**

Figure 8 - Normalized CMI/Event Performance

Another metric designed to establish a performance rating and scale for each SRP circuit was based on the reduction of Events/Year and CMI/Year for those SRP circuits. Since the SRP program should result in fewer vegetation contacts, the outage event count should substantially decrease where work was performed, and associate CMI should also decrease.

Figure 9 shows the results of that analysis, illustrating which circuits had substantial reductions in outage events and associated CMI and which did not.



Circuit	Related Events Per Year Prior	Related Events Per Year Post	Related Events %Change	Related Events Change	Unrelated Events Per Year Prior	Unrelated Events Per Year Post	Unrealated Events %Change	Unrelated Events Change	Related Unrelated Net %Change	Related Unrelated Net Change	Related CMI Per Year Prior	Related CMI Per Year Post	Annual CMI Savings Simple	Annual CMI Savings Related	Annual CMI Savings Net	Annual CMI Savings Related %	Years Prior
F15W17	1.25	0.00	100.00 %	Decrease	2	2.00	33.33 %	Increase	-133.33 %	Improved	17,689	0	17,689	17,689	23,585	100.00 %	4
E54X1	3.50	0.33	90.48 %	Decrease	9	9.00	5.88 %	Increase	-96.36 %	Improved	176,551	1,851	174,700	159,737	170,122	90.48 %	2
E51X1	4.00	2.00	50.00 %	Decrease	11	15.33	46.03 %	Increase	-96.03 %	Improved	178,638	255,230	-76,592	89,319	171,549	50.00 %	2
E47X1	3.00	1.00	66.67 %	Decrease	7	9.00	28.57 %	Increase	-95.24 %	Improved	34,979	11,744	23,235	23,319	33,313	66.67 %	2
C15W1	1.00	0.00	100.00 %	Decrease	11	7.00	33.33 %	Decrease	-66.67 %	Improved	90,859	0	90,859	90,859	60,573	100.00 %	4
F40W42	0.50	0.00	100.00 %	Decrease	2	1.00	50.00 %	Decrease	-50.00 %	Improved	38,677	0	38,677	38,677	19,339	100.00 %	2
F30W31	4.00	2.00	50.00 %	Decrease	28	19.50	30.36 %	Decrease	-19.64 %	Improved	191,749	71,898	119,851	95,874	37,665	50.00 %	1
C13W3	5.25	7.00	33.33 %	Increase	37	54.00	47.95 %	Increase	-14.61 %	Improved	219,953	293,602	-73,649	0	0	0.00 %	4
F39W19	1.67	1.50	10.00 %	Decrease	28	28.00	0.00 %	Unchanged	-10.00 %	Improved	102,072	16,554	85,518	10,207	10,207	10.00 %	3
F39W18	0.67	0.50	25.00 %	Decrease	26	19.00	27.85 %	Decrease	2.85 %	Under Performed	663	82,495	-81,832	166	19	25.04 %	3
C6X3	1.00	0.50	50.00 %	Decrease	19	2.50	86.84 %	Decrease	36.84 %	Under Performed	82,496	35,741	46,755	41,248	30,393	50.00 %	1
F15W16	0.75	1.00	33.33 %	Increase	18	11.00	39.73 %	Decrease	73.06 %	Worsened	35,227	6,140	29,087	0	0	0.00 %	4
Total											1,197,949	933,398	264,551	567,095	556,765	47.34 %	

Figure 9 - Circuit Performance Relative to SRP

By calculating the percent change for the events and related normalized CMI a reasonable avoided annual CMI, or Annual CMI Savings, for each circuit was calculated.

Circuit	Related Events %Change	Related Events Change	Annual CMI Savings Related	Annual CMI Savings Related %	Years Prior	Years Post	LDT CMI Savings Related
F15W17	100.00 %	Decrease	17,689	100.00 %	4	1	17,689
E54X1	90.48 %	Decrease	159,737	90.48 %	2	3	479,211
E51X1	50.00 %	Decrease	89,319	50.00 %	2	3	267,957
E47X1	66.67 %	Decrease	23,319	66.67 %	2	3	69,957
C15W1	100.00 %	Decrease	90,859	100.00 %	4	1	90,859
F40W42	100.00 %	Decrease	38,677	100.00 %	2	3	116,031
F30W31	50.00 %	Decrease	95,874	50.00 %	1	4	383,496
C13W3	33.33 %	Increase	0	0.00 %	4	1	0
F39W19	10.00 %	Decrease	10,207	10.00 %	3	2	20,414
F39W18	25.00 %	Decrease	166	25.04 %	3	2	332
C6X3	50.00 %	Decrease	41,248	50.00 %	1	4	164,992
F15W16	33.33 %	Increase	0	0.00 %	4	1	0
Total			567,095	47.34 %			1,610,938

Figure 10 - Circuit Performance - Annual CMI Savings

The results for 14 SRP circuits, which had associated outage data for one year prior, and one-year post work completion produced a combined 47 percent annual CMI savings. Those 14 circuits had an average of 2.5 years of data pre- and post-work completion with one to four years minimum and maximum. The annual CMI savings were calculated to be ~567K CMI, with total CMI savings post work completion being ~1.6M customer minutes of interruption (from Figure 10 above).

This annual CMI saving of (~1.6M) along with a cost per CMI analysis was used to calculate a reasonable internal savings in dollars as well as external savings to Unitil's customers from avoided revenue losses based on the Interruption Cost Estimate (ICE) calculator, developed by Lawrence Berkeley National Laboratory and Nexant, and funded by the Department of Energy.

To arrive at a Cost/CMI, the costs associated with individual storms was used to calculate a reasonable cost per CMI value. The Cost/CMI utilized individual cost for each storm event as identified by Unitil. Multiple methods were used due to the wide range of values associated with each storm event (4¢ to $2k per CMI). Methods considered included simple outlier exclusion, averages by storm category, regional averages, and trends over time. The metric deemed most reasonable to calculate a Cost/CMI was the average of the mid-quartile Cost/CMI (see Table 1).

Table 1: Unitil Storm Cost/CMI Example Utilizing 2nd and 3rd Quartile Storm Info.

Storm Name	Region	Level	Outage Events	CMI	Storm Cost	Cost/CMI	Quartile	Storm CMI	Cost
Thunderstorm Event (November 3rd, 2018)	MA	Mod	28	506,187	$48,868	$0.10	2	506,187	$48,868
Thunderstorm Event (September 6th, 2014)	MA	Mod	18	427,646	$55,596	$0.13	2	427,646	$55,596
Snow Event (March 31st, 2017)	NH	Mod	61	1,419,671	$197,931	$0.14	2	1,419,671	$197,931
Thunderstorm Event (May 4th, 2018)	NH	Min	39	1,575,462	$228,761	$0.15	2	1,575,462	$228,761
Wind Event (October 30th, 2017)	MA	Min	24	213,942	$31,152	$0.15	2	213,942	$31,152
Thanksgiving Storm Cato (November 26th, 2014)	MA	Mod	53	1,373,149	$289,768	$0.21	2	1,373,149	$289,768
T-Storm/Microburst (July 18th, 2016)	NH	Min	14	1,124,745	$243,879	$0.22	2	1,124,745	$243,879
Winter Storm Grayson (January 4th, 2018)	NH	Min	19	366,659	$147,046	$0.40	2	366,659	$147,046
Winter Storm Riley (March 2nd, 2018)	NH	Min	26	334,469	$153,712	$0.46	2	334,469	$153,712
Winter Storm Skylar (March 13th, 2018)	NH	Nor	12	64,641	$31,722	$0.49	2	64,641	$31,722
Winter Storm Grayson (January 4th, 2018)	MA	Min	8	44,471	$25,607	$0.58	2	44,471	$25,607
Thunderstorm Event (November 3rd, 2018)	NH	Nor	17	54,495	$41,257	$0.76	2	54,495	$41,257
Snow Event (February 13th, 2014)	NH	Min	6	208,511	$159,605	$0.77	2	208,511	$159,605
Wet Snow (February 15th, 2017)	NH	Nor	1	82,569	$63,630	$0.77	3	82,569	$63,630
Winter Storm (February 12th, 2017)	NH	Nor	1	30,008	$24,780	$0.83	3	30,008	$24,780
Snow Storm (December 26th, 2016)	MA	Nor	11	27,418	$27,432	$1.00	3	27,418	$27,432
Noreaster (December 29th, 2016)	NH	Min	14	185,991	$211,166	$1.14	3	185,991	$211,166
Wind Event (February 15th, 2015)	NH	Min	11	211,209	$285,854	$1.35	3	211,209	$285,854
Winter Storm Riley (March 2nd, 2018)	MA	Min	14	64,985	$118,973	$1.83	3	64,985	$118,973
Thunderstorm (July 30th, 2015)	MA	Nor	3	7,410	$19,924	$2.69	3	7,410	$19,924
Thunderstorm Event (July 17th, 2018)	NH	Nor	5	27,210	$85,017	$3.12	3	27,210	$85,017
Wind Event (March 29th, 2016)	NH	Nor	7	29,144	$93,209	$3.20	3	29,144	$93,209
T-Storm Event (June 19th, 2017)	NH	Nor	5	10,818	$35,958	$3.32	3	10,818	$35,958
Wind Storm (February 25th, 2019)	NH	Min	2	84,895	$303,387	$3.57	3	84,895	$303,387
Wind Event (March 12th, 2014)	NH	Nor	6	9,943	$36,670	$3.69	3	9,943	$36,670
							Total	**8,485,648**	**$2,960,904**
								$Cost/CMI	**$0.35**

Eliminating the upper- and lower-25 percent values produced 35¢ per CMI for an internal savings of ~$563K (~1.6M CMI x 35¢ = ~$563K) and external savings of ~$4M for those 14 circuits. ECI believes the savings will be similar in magnitude for the remaining SRP circuits were adequate data was not provided, or those circuits a currently in the process of being worked, yielding two to three times these savings.

2.7 Benefit Analysis

ECI reviewed the analysis results produced to support a cost benefit analysis and recommendations.

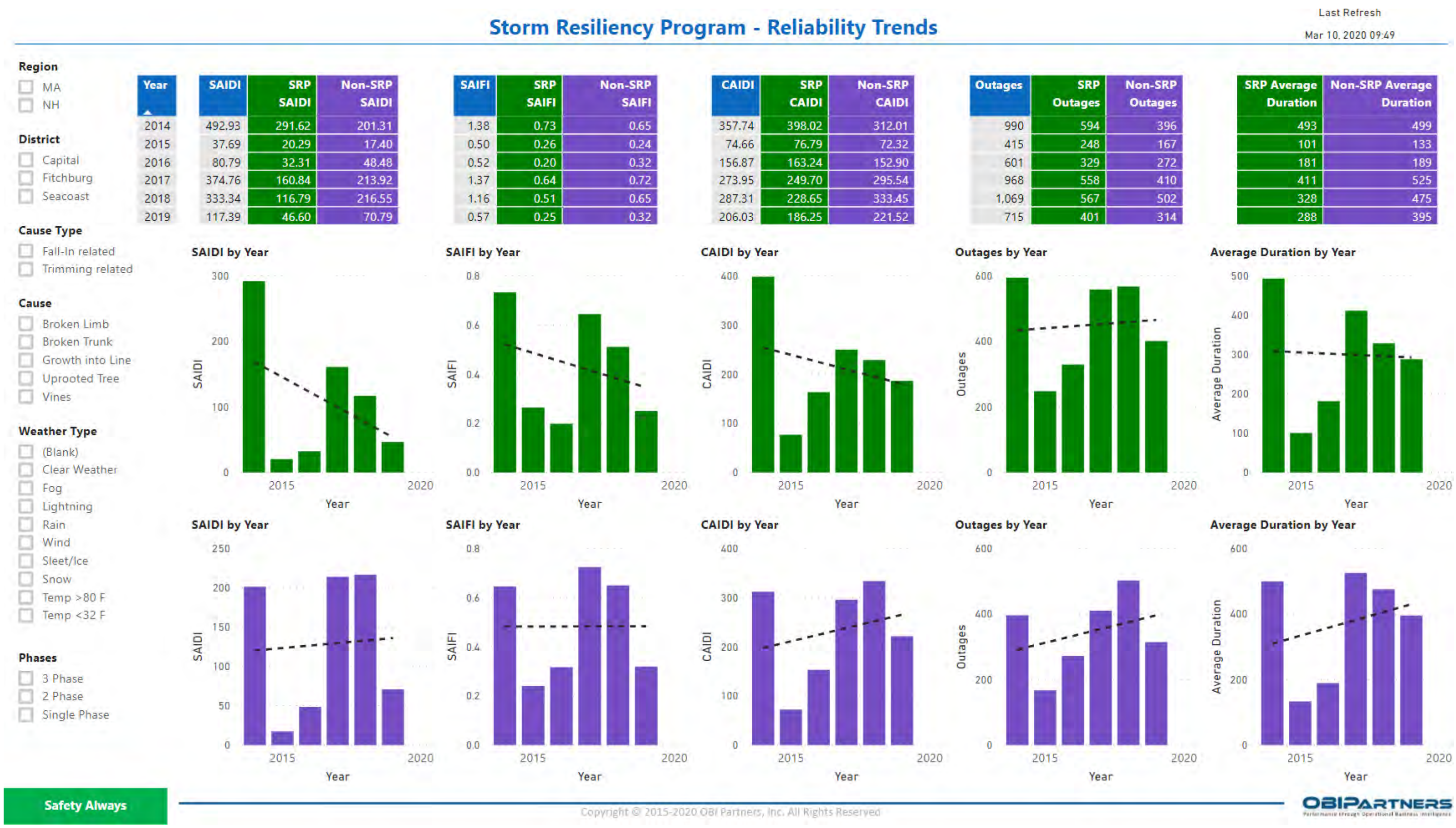
2.7.1 Overall SRP Benefits

ECI reviewed the vegetation management programs for both Unitil-New Hampshire and Unitil-FG&E in 2010. ECI found that tree density in both operational areas to be in the upper quartile of tree densities (New Hampshire-154 trees per mile and FG&E-137 trees per mile) when compared to other utilities throughout the United States (avg. 96 trees per mile). Beginning in 2012, Unitil began a focused Storm Resiliency Program (SRP) to address tree-caused outages. At the core of this program, Unitil began to address overhang removal and additional brush/tree removal on critical line sections impacting the largest portion of their customer base.

Trees overhanging the conductors have been shown to increase customer outages during major ice storm events (Guggenmoos, 2007). As such many utilities in ice prone areas have adopted processes to remove overhanging limbs on priority lines. Priority lines are generally defined as those line sections that if they were to fail, will impact all the customers on that circuit (e.g. feeder backbone) or those line sections deemed to feed critical customers (e.g. industrial, commercial, police, fire, etc.).

The data analysis was used to validate the improvement trends between SRP and non-SRP circuits utilizing the Unitil tree-outage data between 2014 and 2019. Total tree-related outages trends for all weather events and storm only were reviewed for all phases and for three-phase only. The results are presented here in Figure 11 through Figure 16.

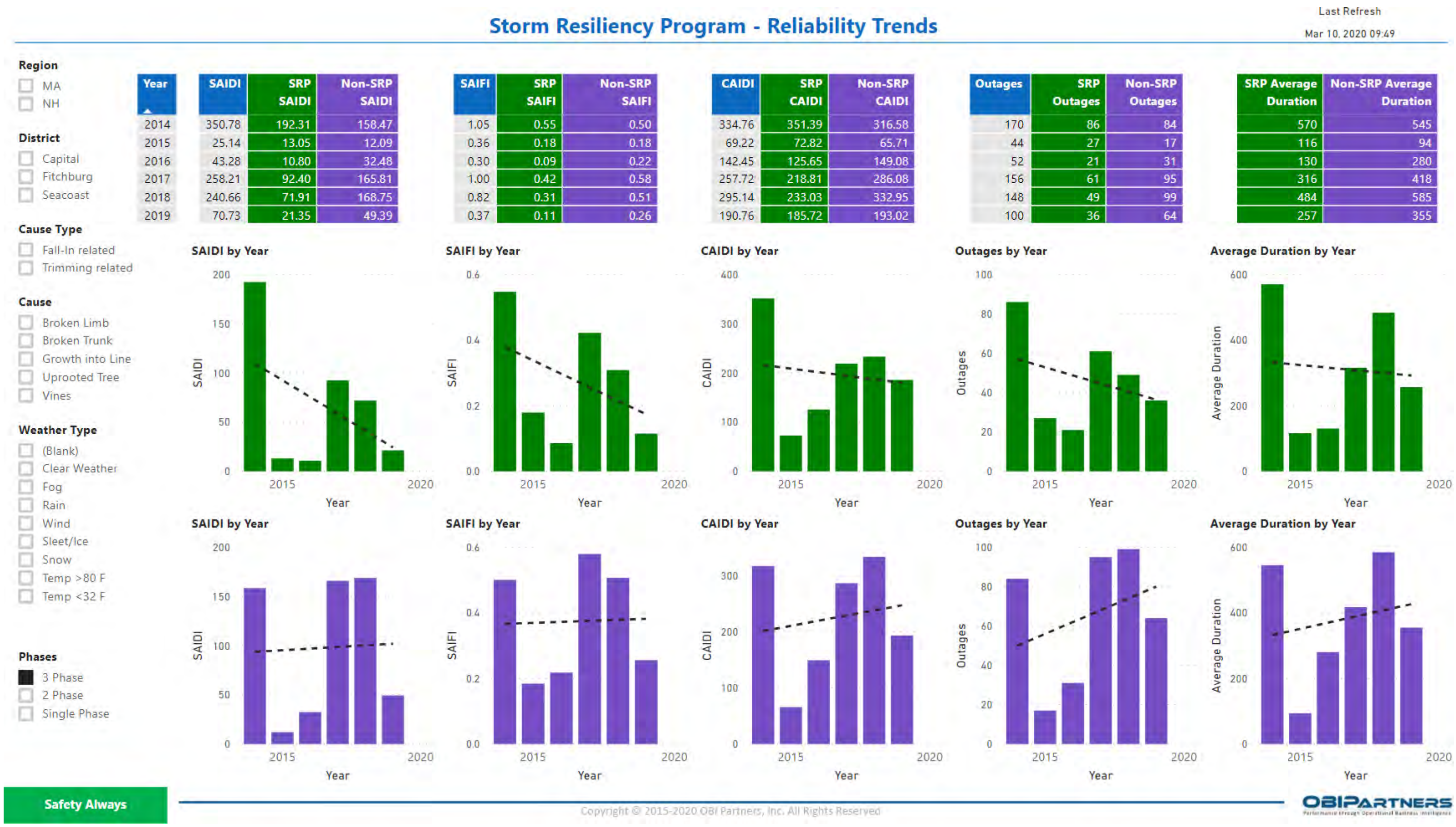
The six trend graphs show a clear improvement trend in SRP circuit performance for SAIDI, SAIFI, and CAIDI as compared to the non-SRP circuit performance. The increase seen in Outages by Year for all phases are due to increases in tree-caused outages (including increased weather-related events) on the single-phase portion of the circuits that were not maintained as part of the SRP program. The largest improvements in SRP circuit performance can be seen in the graphs for three-phase only performance (Figure 12) particularly during storm events (Figure 14).



Year	SAIDI	SRP SAIDI	Non-SRP SAIDI	SAIFI	SRP SAIFI	Non-SRP SAIFI	CAIDI	SRP CAIDI	Non-SRP CAIDI	Outages	SRP Outages	Non-SRP Outages	SRP Average Duration	Non-SRP Average Duration
2014	492.93	291.62	201.31	1.38	0.73	0.65	357.74	398.02	312.01	990	594	396	493	499
2015	37.69	20.29	17.40	0.50	0.26	0.24	74.66	76.79	72.32	415	248	167	101	133
2016	80.79	32.31	48.48	0.52	0.20	0.32	156.87	163.24	152.90	601	329	272	181	189
2017	374.76	160.84	213.92	1.37	0.64	0.72	273.95	249.70	295.54	968	558	410	411	525
2018	333.34	116.79	216.55	1.16	0.51	0.65	287.31	228.65	333.45	1,069	567	502	328	475
2019	117.39	46.60	70.79	0.57	0.25	0.32	206.03	186.25	221.52	715	401	314	288	395

Figure 11 - SRP vs. Non-SRP Circuit Performance for All Phases and All Weather Events

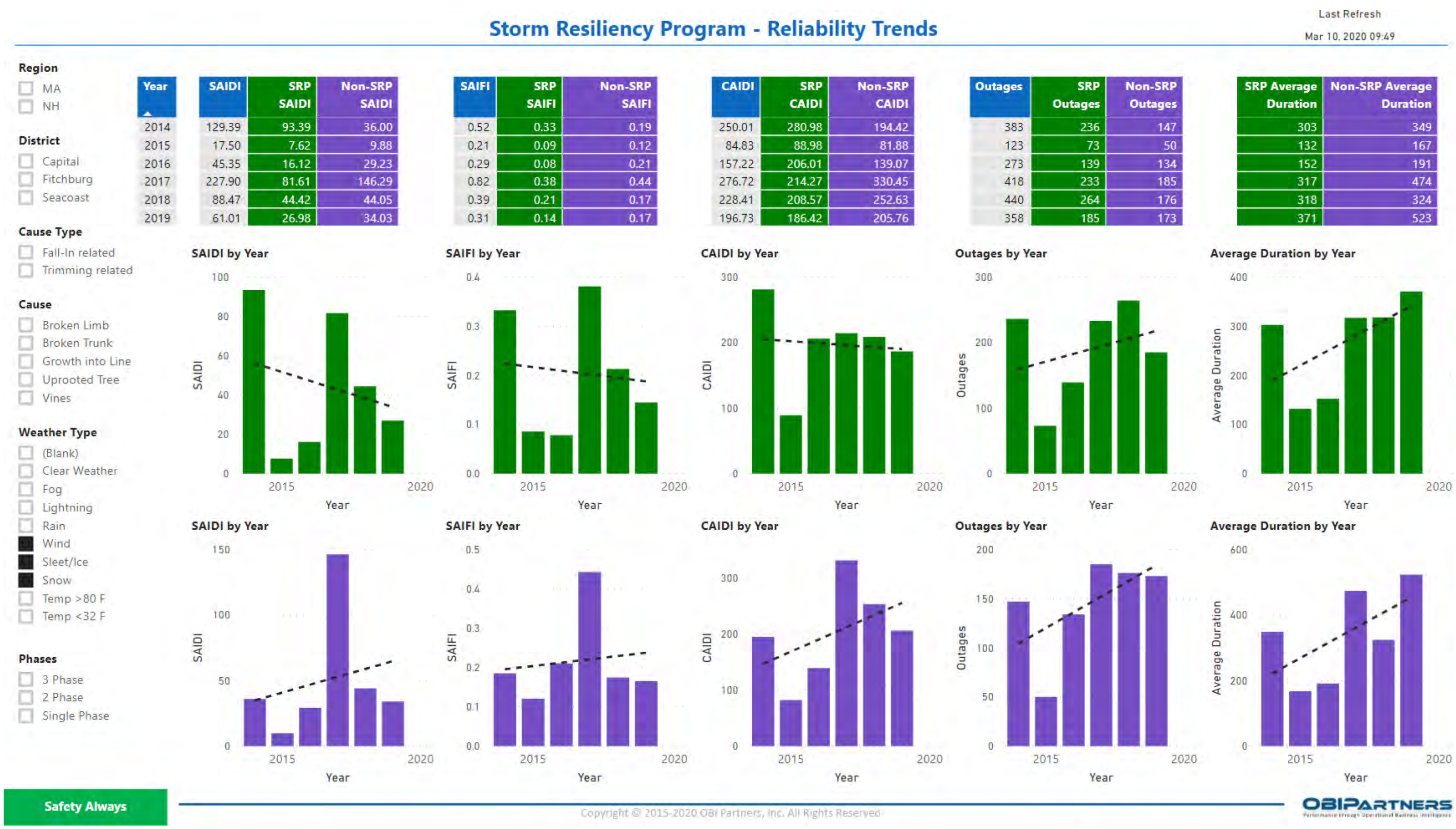
The figure above shows that when considering all outages, the SRP circuits outperformed the Non-SRP circuits based on all indices.



Year	SAIDI	SRP SAIDI	Non-SRP SAIDI	SAIFI	SRP SAIFI	Non-SRP SAIFI	CAIDI	SRP CAIDI	Non-SRP CAIDI	Outages	SRP Outages	Non-SRP Outages	SRP Average Duration	Non-SRP Average Duration
2014	350.78	192.31	158.47	1.05	0.55	0.50	334.76	351.39	316.58	170	86	84	570	545
2015	25.14	13.05	12.09	0.36	0.18	0.18	69.22	72.82	65.71	44	27	17	116	94
2016	43.28	10.80	32.48	0.30	0.09	0.22	142.45	125.65	149.08	52	21	31	130	280
2017	258.21	92.40	165.81	1.00	0.42	0.58	257.72	218.81	286.08	156	61	95	316	418
2018	240.66	71.91	168.75	0.82	0.31	0.51	295.14	233.03	332.95	148	49	99	484	585
2019	70.73	21.35	49.39	0.37	0.11	0.26	190.76	185.72	193.02	100	36	64	257	355

Figure 12 - SRP vs. Non-SRP Circuit Performance for Three-Phase Only and All Weather Events

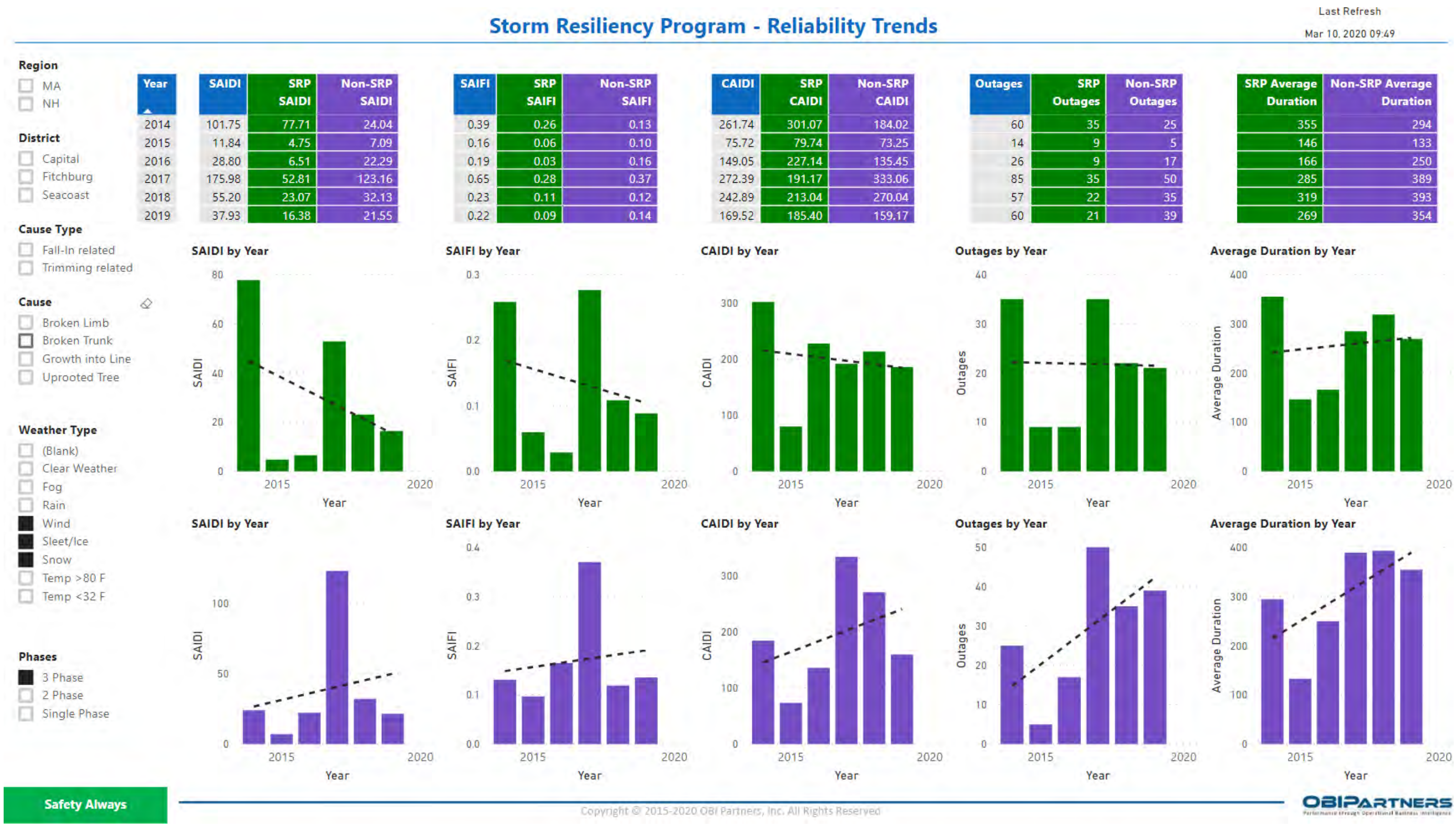
The figure above shows that when considering three-phase outages, the SRP circuits also outperformed the Non-SRP circuits based on all indices.



Year	SAIDI	SRP SAIDI	Non-SRP SAIDI	SAIFI	SRP SAIFI	Non-SRP SAIFI	CAIDI	SRP CAIDI	Non-SRP CAIDI	Outages	SRP Outages	Non-SRP Outages	SRP Average Duration	Non-SRP Average Duration
2014	129.39	93.39	36.00	0.52	0.33	0.19	250.01	280.98	194.42	383	236	147	303	349
2015	17.50	7.62	9.88	0.21	0.09	0.12	84.83	88.98	81.88	123	73	50	132	167
2016	45.35	16.12	29.23	0.29	0.08	0.21	157.22	206.01	139.07	273	139	134	152	191
2017	227.90	81.61	146.29	0.82	0.38	0.44	276.72	214.27	330.45	418	233	185	317	474
2018	88.47	44.42	44.05	0.39	0.21	0.17	228.41	208.57	252.63	440	264	176	318	324
2019	61.01	26.98	34.03	0.31	0.14	0.17	196.73	186.42	205.76	358	185	173	371	523

Figure 13 - SRP vs. Non-SRP Circuit Performance for All Phases and Storm Only Events

The figure above shows that when considering all outages under storm conditions, the SRP circuits outperformed the Non-SRP circuits based on all indices.



Year	SAIDI	SRP SAIDI	Non-SRP SAIDI	SAIFI	SRP SAIFI	Non-SRP SAIFI	CAIDI	SRP CAIDI	Non-SRP CAIDI	Outages	SRP Outages	Non-SRP Outages	SRP Average Duration	Non-SRP Average Duration
2014	101.75	77.71	24.04	0.39	0.26	0.13	261.74	301.07	184.02	60	35	25	355	294
2015	11.84	4.75	7.09	0.16	0.06	0.10	75.72	79.74	73.25	14	9	5	146	133
2016	28.80	6.51	22.29	0.19	0.03	0.16	149.05	227.14	135.45	26	9	17	166	250
2017	175.98	52.81	123.16	0.65	0.28	0.37	272.39	191.17	333.06	85	35	50	285	389
2018	55.20	23.07	32.13	0.23	0.11	0.12	242.89	213.04	270.04	57	22	35	319	393
2019	37.93	16.38	21.55	0.22	0.09	0.14	169.52	185.40	159.17	60	21	39	269	354

Figure 14 - SRP vs. Non-SRP Circuit Performance for Three-Phase Only and Storm Only Events

The figure above shows that when considering three-phase outages under storm conditions, the SRP circuits <u>substantially</u> outperformed the Non-SRP circuits based on all indices.

Storm Resiliency Program - Reliability Trends

Last Refresh
Mar 10, 2020 09:49

Region
- ☐ MA
- ☐ NH

District
- ☐ Capital
- ☐ Fitchburg
- ☐ Seacoast

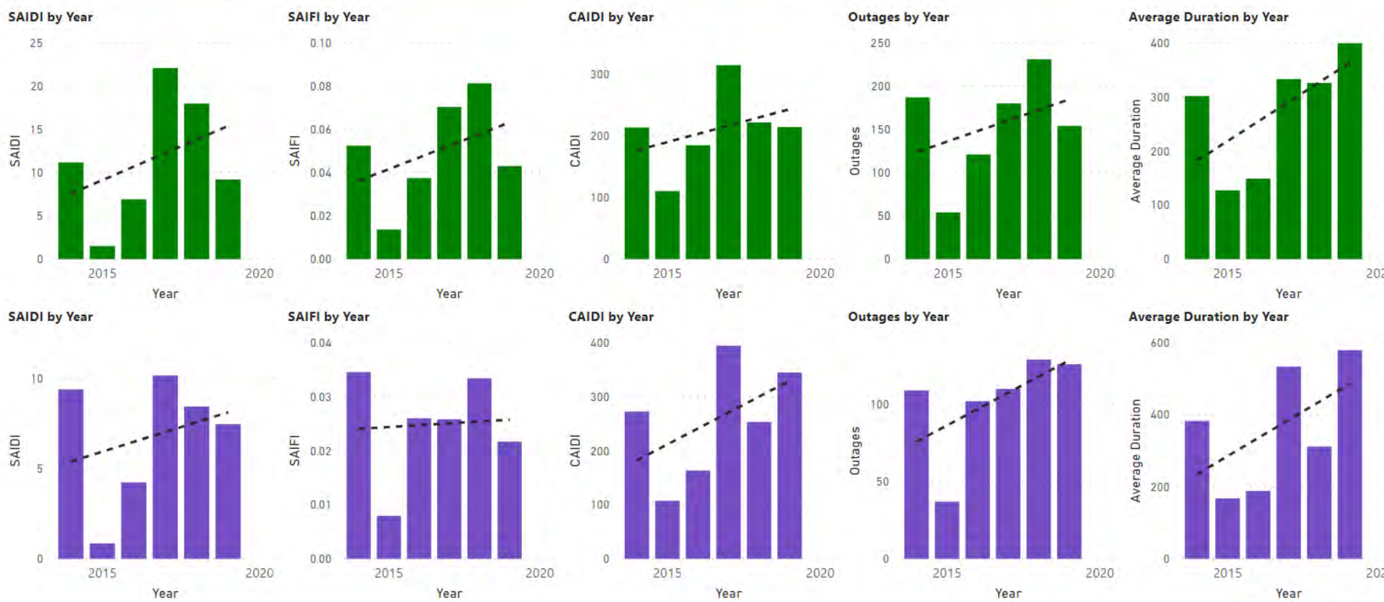
Cause Type
- ☐ Fall-In related
- ☐ Trimming related

Cause
- ☐ Broken Limb
- ☐ Broken Trunk
- ☐ Growth into Line
- ☐ Uprooted Tree
- ☐ Vines

Weather Type
- ☐ (Blank)
- ☐ Clear Weather
- ☐ Fog
- ☐ Lightning
- ☐ Rain
- ■ Wind
- ■ Sleet/Ice
- ■ Snow
- ☐ Temp >80 F
- ☐ Temp <32 F

Phases
- ☐ 3 Phase
- ☐ 2 Phase
- ■ Single Phase

Year	SAIDI	SRP SAIDI	Non-SRP SAIDI	SAIFI	SRP SAIFI	Non-SRP SAIFI	CAIDI	SRP CAIDI	Non-SRP CAIDI	Outages	SRP Outages	Non-SRP Outages	SRP Average Duration	Non-SRP Average Duration
2014	20.58	11.18	9.40	0.09	0.05	0.03	236.61	213.07	272.38	296	187	109	302	383
2015	2.36	1.51	0.85	0.02	0.01	0.01	109.13	110.15	107.37	91	54	37	127	168
2016	11.15	6.91	4.24	0.06	0.04	0.03	175.71	184.33	163.28	223	121	102	149	188
2017	32.26	22.09	10.18	0.10	0.07	0.03	335.47	313.90	394.27	290	180	110	333	533
2018	26.45	17.99	8.45	0.11	0.08	0.03	230.55	221.23	253.23	360	231	129	326	312
2019	16.67	9.20	7.47	0.06	0.04	0.02	257.52	213.68	344.61	280	154	126	399	579



Safety Always

OBIPARTNERS

Figure 15 - SRP vs. Non-SRP Circuit Performance for Single-Phase Only and Storm Only Events

The figure above shows that when considering single phase outages under storm conditions, the SRP circuits tracked along the Non-SRP circuits as would be expected since they did not receive any enhanced trimming. Additionally, the increase in the Outage count for the SRP circuits that are in contrast to the reduction in outages for the three-phase SRP circuits from the prior figure, are likely due to previously unaccounted nested outages on laterals and services.

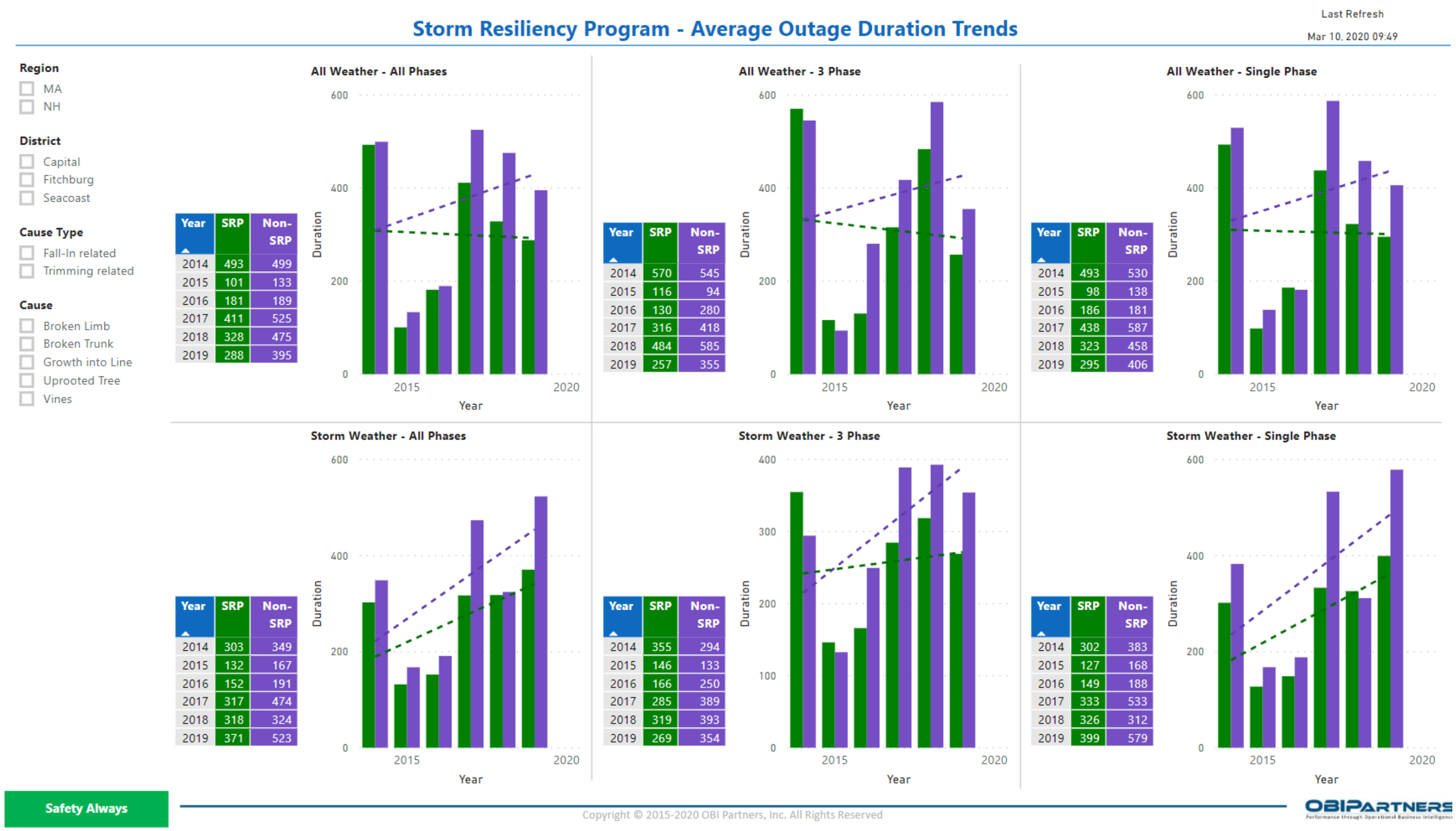


Figure 16 – SRP vs. Non-SRP Average Outage Duration Comparisons

The figure above shows a comparison of Average Outage Durations for SRP and Non-SRP circuits related to various weather conditions and phases. The Average Outage Duration under all circumstances is lower for SRP circuits than Non-SRP circuits, with three-phase outages in storm conditions showing a significant difference in both the trend and average duration minutes. Additionally, the significant SRP based improvement is also validated by comparing storm condition three-phase against single-phase duration trends and duration minutes.

2.7.2 Cost/Benefit Analysis

Utilizing the estimated annual CMI avoided estimate of 567,095 (from Figure 10) for the 14 circuits studied, it can be roughly estimated that the cumulative CMI avoided for the 31 New Hampshire SRP circuits completed to date as well as the 11 Massachusetts completed SRP circuits totaled approximately 1.7M per year. It can therefore be assumed that the additional 22 remaining SRP circuits will produce an additional 891K CMI avoided per year or a total of 2.9M CMI avoided per year for all 74 planned SRP circuits going forward.

Utilization of cost per CMI of 35¢, which represents the mid-quartile cost per storm CMI for both New Hampshire and Massachusetts, is estimated to be a conservative estimate of what Unitil may expect. The total direct (internal) cost avoided to Unitil is estimated to be approximately $1.02M per year (35¢ per CMI x 2.9M CMI avoided) for all 74 planned SRP circuits once complete.

Total SRP spend for the 42 circuits completed through 2019 totals $13.44M or approximately $39,308.85 per mile complete. It is estimated that the completion of all 74 planned SRP circuits will cost approximately $18.76M total or $1.88M per year assuming a total 10-year completion timeframe. It is obvious that the internal cost avoided alone falls short of justifying the SRP program expenditures. However, when considering the total cost avoided, it is important to include external costs. External cost avoidance includes items such as lost revenue, customer dissatisfaction, lost production hours to business and industry and other societal costs.

Using the annual SAIDI, SAIFI and CAIDI savings (Figure 17) with the Interruption Cost Estimate (ICE) calculator, the following **external** savings results for New Hampshire was estimated:

Circuit	Related Events Per Year Prior	Related Events Per Year Post	Related Events %Change	Related Events Change	CMI Per Year Prior	Annual CMI Savings %	Related CI	Annual CMI Savings	Annual SAIDI Savings	Annual SAIFI Savings	Annual CAIDI Savings
C6X3	1.00	0.50	50.00 %	Decrease	82,496	50.00 %	2,251.00	41,248	0.28	0.0038	27.71
C8X3	1.00	1.75	75.00 %	Increase	9,325	0.00 %	4,131.00	0	0.00	0.0000	0.00
E47X1	3.00	1.00	66.67 %	Decrease	34,979	66.67 %	1,219.00	23,319	0.31	0.0043	34.85
E51X1	4.00	2.00	50.00 %	Decrease	178,638	50.00 %	7,791.00	89,319	1.60	0.0235	32.77
E54X1	3.50	0.33	90.48 %	Decrease	176,551	90.48 %	2,049.00	159,737	1.59	0.0089	85.53
F11W11	0.50	1.00	100.00 %	Increase	19,071	0.00 %	1,099.00	0	0.00	0.0000	0.00
F15W16	0.75	1.00	33.33 %	Increase	35,227	0.00 %	2,739.00	0	0.00	0.0000	0.00
F15W17	1.25	0.00	100.00 %	Decrease	17,689	100.00 %	709.00	17,689	0.22	0.0022	33.26
F30W31	4.00	2.00	50.00 %	Decrease	191,749	50.00 %	5,823.00	95,874	0.35	0.0080	8.66
F39W18	0.67	0.50	25.00 %	Decrease	663	25.04 %	1,342.00	166	0.00	0.0000	0.29
F39W19	1.67	1.50	10.00 %	Decrease	102,072	10.00 %	3,353.00	10,207	0.10	0.0009	3.36
F40W42	0.50	0.00	100.00 %	Decrease	38,677	100.00 %	739.00	38,677	0.18	0.0017	26.17
Total					1,197,949	47.34 %	46,429.00	567,095	5.20	0.0588	269.79

Figure 17 - Circuit Performance - Annual Reliability Savings

General inputs:	State = **New Hampshire**	Residential Customers = **90,000**	Non-Residential = **17,000**
Analysis Values:	Annual SAIFI Savings = **0.0588**	Annual SAIDI Savings = **5.20**	Annual CAIDI Savings = **269.79**

ICE data inputs and results:

Inputting SAIFI of **0.0588** and of SAIDI of **5.20**

Results in ICE calculated CAIDI of ***88.4*** and savings of ***$1.246M*** Total Annual External Savings

Inputting SAIFI of **0.0588** and CAIDI of **269.74**

Results in ICE calculated SAIDI of ***15.9*** and savings of ***$3.187M*** Total Annual External Savings

Inputting SAIDI of **5.20** and CAIDI of **269.74**

Results in ICE calculated SAIFI of ***0.019*** and savings of ***$1.030M*** Total Annual External Savings

SAIFI	SAIDI	CAIDI	#Residential	#Non-Residential	
0.0588	5.2	88.4	90,000	17,000	New Hampshire

Interruption Cost Estimates

Sector	# of Customers	Cost Per Event (2016$)	Cost Per Average kW (2016$)	Cost Per Unserved kWh (2016$)	Total Cost (2016$)
Residential	90,000	$5.68	$6.64	$4.51	$30,081.66
Small C&I	16,564	$890.96	$308.49	$209.38	$867,762.20
Medium and Large C&I	436	$13,612.74	$75.24	$51.06	$348,987.20
All Customers	**107,000**	**$198.17**	**$104.06**	**$70.63**	**$1,246,831.06**

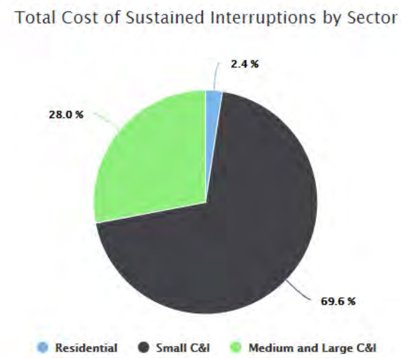


Figure 18 - ICE Calculator Result

Extrapolating calculations performed utilizing the ICE model, the **external** only cost avoided will yield between $5.44M and $16.85M per year for all 74 planned SRP circuits. The internal and external total cost avoided therefore, is estimated to be between $6.46M and $17.87M per year. Net cost avoided after funding the SRP program will yield between $4.58M and $15.99M per year.

3.0 **SUMMARY**

The benefits of a well-structured and targeted ground-to-sky maintenance program are well documented. As supported by the Unitil SRP analysis, it is estimated that Unitil will avoid approximately 2.9M CMI per year for the 74 SRP planned circuits and a net cost avoided (after fully funding the current SRP program) between $4.58M and $15.99M per year. ECI recommends that Unitil be allowed to continue their current SRP program with funding to continue that program into the future to help ensure the continued reduction in tree-related outages.

ECI believes Unitil could augment the Storm Resiliency Program and continue to reduce storm damage and impact on customers by utilizing a similar platform as established for this analysis to define best SRP circuit segment candidates using Outage Data, LiDAR data, additional GIS data and vegetation work data.

4.0 RECOMMENDATIONS

4.0 General Recommendations

The General Recommendations listed below are provided by ECI to support the findings of this report.

- Unitil should continue its current SRP program on the currently planned 74 circuits. The data analysis demonstrates an estimated 2.9M CMI avoided per year and a net internal/external cost avoided (after fully funding the SRP program) between $4.58M and $15.99M per year.
- Unitil should request additional future funding to continue the SRP program and complete the remaining 74 circuits not currently planned.
- Additional data that may be available for work performed in the early years of the SRP Program should be used to derive SRP locations from earlier periods to expand the current analysis.
- Utilize additional LiDAR data to support the identification of re-growth or worsening tree conditions, to begin developing future predictive models to provide outage probabilities and "hot spots".
- Utilize historic outage concentrations with facility data and LiDAR data to determine high impact and high ROI circuit segments to prioritize future SRP work locations.
- Perform weather analysis based on available weather station data across the Unitil system to develop correlation models between wind speed and tree damage.
- The **LiDAR** data provided valuable insight about vegetation conditions and was critical in correlating data from Outage Management and GIS to determine event cause. Continued usage of LiDAR and Imagery to inspect outage causes will help Unitil to refine their understanding of events and work more proactively to prevent outages.

5.0 LITERATURE CITED

1. Guggenmoos, S. (2007). Increased Risk of Electric Service Interruption Associated with Tree Branches Overhanging Conductors. Transmission & Distribution World, Penton Media, Inc., June 2007, New York, NY.
2. Interruption Cost Estimate (ICE) calculator, developed by Lawrence Berkeley National Laboratory and Nexant, and funded by the Department of Energy.

[THIS PAGE INTENTIONALLY LEFT BLANK]

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY

OF

CAROLE A. BEAULIEU

EXHIBIT CAB-1

New Hampshire Public Utilities Commission

Docket No. DE 21-030

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Carole Beaulieu. My business address is 5 McGuire Street, Concord, NH 03301.

Q. What is your position and what are your responsibilities?

A. I am the Manager of Credit and Collections of Unitil Service. Unitil Service provides centralized utility management services to Unitil Corporation's utility operating subsidiaries including Unitil Energy Systems, Inc. ("UES" or the "Company"). I am responsible for maximizing the collection of Accounts Receivables and minimizing future bad debt on behalf of all of our customers. I plan and direct the activities within the department as it relates to customer and systems processes for the various collections activities, such as proactive communications to customers with delinquent balances, generation of disconnection notices, shut offs for non-payment and pursuit of unpaid final account balances. I oversee the activities of Customer Service and Credit Representatives relating to support of customers who need assistance with paying their bill, such as offering a variety of payment plans, advice on reducing energy costs, and referral to external agencies such as the Community Action Agency programs ("CAP") for additional financial assistance.

Q. Please describe your educational and professional background.

A. I hold a Bachelors of Arts degree in Psychology from the University of Rhode Island. I started my career with AT&T and held a variety of management positions in the company for over 18 years. My roles included management roles within the Customer Service and Collections Department of the AT&T call center, and various Marketing and Program Management roles. I joined Unitil Service as the Supervisor of Credit in October 2009 and was promoted to my current role as the Manager of Credit and Collections in February 2011.

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("Commission")?

A. No, I have not.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to propose a new program that the Company views as an impactful and necessary step to assist customers who may be facing financial challenges as well as difficulty in paying often significant energy arrears. UES is proposing an Arrearage Management Program ("AMP") for residential financial hardship customers who are struggling to pay their electric bill.

Q. Please summarize your testimony.

A. The Company is seeking approval to offer an AMP. The AMP will offer qualifying residential customers of UES immediate relief to reduce their current and future energy burdens through a flexible payment arrangement and arrears forgiveness program. In addition, while the CAP is working with the customer to determine their income eligibility, they will offer budget counseling services, home weatherization and other energy efficiency initiatives, as appropriate. It is the goal of the Company that this program will provide relief and education to income eligible customers who are overwhelmed by their current arrearage balances. The Company's AMP offering will provide assistance to improve the customer's ability to better manage their payments more effectively. I also discuss how the Company proposes to recover costs associated with the AMP.

Q. How have you organized your testimony?

A. My testimony will first discuss the program design, followed by the cost to implement the program and the how the Company proposes to recover the cost.

II. ARREARAGE MANAGEMENT PROGRAM PROPOSAL

Q. Please explain the program that the Company is proposing to offer.

A. This program will be offered to all UES customers who are coded as Financial Hardship according to the NH PUC 1200 rules. Financial Hardship customers will be offered enrollment in a budget billing payment plan where they will pay their average bill each month.

All customers will be referred to their local CAP to apply for Fuel Assistance. If a customer receives a Fuel Assistance or other social agency pledge for their electric service, their monthly payment amount will be reduced, reinforcing the value of seeking out assistance annually. Each month that a customer pays their monthly payment plan amount, UES will forgive up to $400 per month, for a maximum annual arrearage forgiveness of $4,800. For customers with an arrearage that exceeds the annual forgiveness allowed, as long as the customer continues to pay their monthly payment plan amount, the program will continue each year until the customer's past due amount is fully forgiven.

Q. Please describe how the AMP will benefit the customer.

A. The goal of the AMP is to provide UES's customers the opportunity to successfully manage and pay for their energy usage. Successfully accomplishing this goal will stop the pattern of building arrears, being disconnected, and carrying additional debt. Through participation in this program, UES's customers will be afforded many benefits, such as the prevention of late fees and disconnection of their service, the opportunity to have past due balances forgiven over a minimum of a 12 month period, a reminder to seek assistance programs such as the Electric Assistance Program to reduce their rate, and Fuel Assistance for monetary grants. Once their arrearages are reduced to a manageable level, it is our goal that the customer will acquire a long term habit of consistent monthly payment behavior, which will also help them avoid future delinquency with all their monthly personal expenses. Participating customers will also have a better opportunity to improve their overall credit rating and the ability to better manage other bills. With the COVID pandemic, customers have faced significant financial challenges, and this program will enhance communications between UES, customers, and social agencies to best support customers in their time of need.

Q. Have similar programs been approved by the Commission?

A. Yes. The Commission recently approved a similar arrearage forgiveness program in Docket DE 19-057. In that docket Commission Staff provided general support for an arrearage forgiveness program and stated other customer benefits including, "the enhancement of communications between customers, social service agencies and the utility and other non-utility benefits that are difficult to measure such as the impact on customers' safety, health, and nutrition. The program should also reduce the utility's costs for collections, field visits, disconnections, reconnections, lead lag, carrying costs and uncollectables." Docket No. 19-197, Noonan Testimony at 6.

Q. What are the eligibility criteria for a customer to qualify to be enrolled in the AMP?

A. To be eligible for this proposed AMP, a customer must meet the following:

- Be an active residential customer of record with UES.
- The customer of record must reside at the location where the utility service is provided.
- The customer must be coded as Financial Hardship in our Customer Information System, evidenced by participation in one of the programs identified in the NHPUC 1200 rules.
- Have an arrearage of at least $300 that is a minimum 60 days delinquent.

Q. How will the program be administered?

A. The program will be administered as follows:

- When a customer calls into the Company, once the Customer Service Representative has determined that the customer meets the eligibility criteria, they will be offered the AMP and then be transferred to the AMP Coordinator for enrollment if they choose to participate.

- In addition, the Company will proactively reach out to individual customers who meet the criteria for the AMP program to discuss the program benefits and enroll customers who choose to participate.
- Customers who are enrolled in the program will receive an AMP welcome letter which includes the required monthly payment amount, direction to pay each month on or before the bill's due date, and the monthly forgiveness credit amount.
- Customers who were disconnected for non-payment can be reconnected after enrolling in the AMP and paying their first month's payment plan amount.
- The AMP Coordinator will review the enrollees' accounts each month and will issue the advised monthly forgiveness credits when the customer pays the monthly payment plan amount.
- The customer's account will be reviewed quarterly to determine if the amount of the agreed-upon payment is in line with their actual usage. In the event the payment amount is not sufficient to cover the actual usage or the amount the customer is paying is more than the average amount originally calculated, the customer will be notified and the payment plan will be adjusted. Payment plans will only be adjusted if the amount is different by more than $10.00 per month.
- If a customer fails to make the agreed upon payment by the due date, the customer will be notified that in order to remain in the program, the missed payment must be received. After two months of missed payments, the customer will be removed from

the program and they will be notified by letter, which will include direction that they can be re-instated into the program by making up all missed payments.

- Once a customer has successfully completed the program, the AMP Coordinator will encourage them to enroll in a standard budget plan so that they can continue their previous year's success maintaining an average monthly bill payment.

Q. Are there opportunities for re-enrollment in the AMP?

A. Yes. There are two circumstances when a customer may re-enroll in the AMP:

1. Twelve (12) months after a customer is removed from the AMP for non-payment, customers will be afforded the opportunity to enroll in a new AMP payment plan for their entire balance, if they continue to meet the program eligibility requirements.
2. When 12 months have passed after successfully completing the AMP program, a customer may enroll in the program again by meeting the same original criteria.

Q. When is the Company requesting to begin offering the AMP?

A. The Company is seeking approval to begin offering the AMP on April 1, 2022 at the time the Company proposes that permanent rates will be effective.

III. ESTIMATED ANNUAL PROGRAM COSTS

Q. What are the estimated costs to offer the program?

A. Based on current program eligible arrearage balances, the Company is estimating that the annual cost of arrearage forgiveness to be $375,000. This assumes an average enrollment rate of approximately 65 percent and an annual success rate of approximately 50 percent, based on the current eligible population of over 600 customers. See chart below for supporting calculations:

Forecasted AMP Forgiveness					
Forecasted Number of Enrollees	Amount of Enrollee Arrears	Max Amount that Could be Forgiven in 12 Months	Forecasted Enrollment Rate	Forecasted Success Rate	Forgiveness Amount
638	$1,500,000	$1,155,000	65%	50%	$375,000

Q. Are there other costs associated with the program?

A. Yes, in order to administer the program, the Company will need to hire an AMP Coordinator who will be in charge with enrolling and monitoring the participants in the program and make necessary adjustments to individual customers payment terms. This estimated cost associated with the new full time position including benefits is estimated to be $84,000.

Q. How does the Company propose to recover the costs associated with the AMP?

A. The Company is proposing to recover $459,000[1] ($375,000 + $84,000) in distribution rates. Actual incremental costs directly related to the AMP will be tracked and any

[1] Refer to Schedule RevReq-3-14, Line 3.

difference between the actual costs above or below the amount in distribution rates will be reconciled through the External Delivery Charge ("EDC"). Incremental costs include, but are not limited to, labor to administer the AMP and amounts forgiven under the AMP.

IV. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

[THIS PAGE INTENTIONALLY LEFT BLANK]

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY

OF

JONATHAN A. GIEGERICH, CPA

EXHIBIT JAG-1

New Hampshire Public Utilities Commission

Docket No. DE 21-030

TABLE OF CONTENTS

List of Exhibits

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jonathan A. Giegerich. My business address is 6 Liberty Lane West, Hampton, New Hampshire 03842.

Q. What is your position and what are you responsibilities?

A. I am the Tax Manager of Unitil Service Corp. ("Unitil Service"), a subsidiary of Unitil Corporation ("Unitil Corp") that provides a variety of administrative and professional services including, regulatory, financial, accounting, human resources, engineering, operations, information systems technology and energy supply management services to Unitil Corp's utility subsidiaries, including Unitil Energy Systems, Inc. ("UES" or the "Company").

Q. Please describe your business and educational background.

A. I have over 10 years of professional experience in public accounting and the utility industry focused in the tax and regulatory areas. I completed my public accounting requirements at Wager & Associates, LLC in 2009 and I am a Certified Public Accountant in the Commonwealth of Massachusetts, the State of New Hampshire, and the State of Maine. I joined Unitil Service in 2009 as a Corporate Tax Specialist. In 2016 I assumed my current responsibilities as Tax Manager. I hold a Bachelor of Science degree from Bob Jones University and a Master's of Science degree in Taxation from the Sawyer Business School at Suffolk University.

Q. Have you previously testified before this Commission or other regulatory agencies?

A. Yes, most recently I have provided expert written and oral testimony, on behalf of Unitil Corp and its regulated utility subsidiaries, in litigation regarding property tax assessments in New Hampshire. I have also testified on behalf of Unitil Corp numerous times in federal income tax matters before the Internal Revenue Service ("IRS"), and have represented Unitil Corp and its natural gas distribution company (Northern Utilities, Inc.) in Maine on state income tax and sales and use taxes audits. Additionally, I have testified before the Maine Public Utilities Commission on behalf of Unitil Corp and Northern Utilities, Inc. This is my first formal testimony in a rate case proceeding in New Hampshire.

II. SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purposes of my testimony is to describe the effect of the Tax Cuts and Jobs Act of 2017 ("TCJA"), the Coronavirus Aid, Relief, and Economic Security ("CARES") Act, and the Families First Coronavirus Response Act ("FFCRA") on UES's accounting for income taxes and how those effects are presented in the current rate case cost of service schedules. My TCJA, CARES Act, and FFCRA discussion will include three topics: (1) the effect of the new federal corporate income tax rate, which was lowered to 21% from 34% effective January 1, 2018 by the TCJA, on UES's revenue requirements presented in the cost of service in this proceeding; (2) the effect of the flow back of excess Accumulated Deferred Income Taxes ("ADIT") created by the revaluation of ADIT balances at December 31, 2017 at the new 21% rate which is recognized as a Regulatory Liability to be amortized in UES's cost of service; and (3) the pandemic tax relief provided in the CARES Act and FFCRA. Additionally, I explain that the amortization of the excess ADIT Regulatory Liability will reduce UES's operating expenses in the cost of service and the Regulatory Liability amount will be included in the determination of rate base in the new calculation of base rates. My testimony will discuss the effect of the TCJA on the Company's cash flow, rate base, and earned return on common equity ("ROCE").

III. TAX CUTS AND JOBS ACT OF 2017

Q. Please explain the significance of the TCJA.

A. The TCJA is the most recent extensive federal tax code reform and corporate income tax rate reduction since the Tax Reform Act of 1986. While congressional tax changes were administered after the Tax Reform Act of 1986, none of them changed the tax rate structure and tax deduction provisions as significantly as the TCJA. The TCJA lowered the top federal corporate income tax rate from 35% to 21%. Additionally, the TCJA ended certain utility tax provisions including bonus depreciation. The combination of these two changes significantly reduces the Company's cash flows from base rates and reduces the availability of tax deferred funding advantages previously available from the federal government in the form of accelerated tax deductions.

Please see Exhibit JAG-2 for the Company's internal analysis of the TCJA and quarterly tax accounting updates.

Q. Did the Company reduce the federal tax rate to 21% in determining its revenue requirements?

A. Yes, the Company reduced the federal tax rate to 21% in 2018. The Company has reflected this change in its annual cost of service, revenue requirements and base rates in accordance with the principles and requirements contained in the Company's tax sharing agreement, attached as Exhibit JAG – 4.

Q. What determines the amount of ADIT reported on UES's balance sheet?

A. ADIT represents future taxes payable or receivable to federal and state taxing authorities. ADIT are recognized as the tax effect of book/tax temporary differences occurring in the reporting period and measured at the balance sheet date.

Q. What are book/tax temporary differences?

A. Book/tax temporary differences are revenue and expense reporting differences between Generally Accepted Accounting Principles ("GAAP") used by most companies and what the Internal Revenue Code ("IRC") requires most companies to report on their tax returns. Generally, companies follow GAAP and record a provision for current income taxes on their book earnings before income tax or "Pre-Tax Income." Companies that are taking advantage of accelerated tax deductions in the IRC also record a deferred tax benefit in the period. In those cases, the sum of the current provision and the deferred benefit is the company's tax expense for the period.

Q. Please give an example of a book/tax temporary difference.

A. A common book/tax temporary difference is the differences between GAAP and tax depreciation rates. Tax depreciation rates are generally more accelerated under the IRC's Modified Accelerated Cost Recovery System ("MACRS") as compared to GAAP depreciation rates. Book/tax temporary depreciation rate differences cause Pre-Tax Income for GAAP and Taxable Income reported to the IRS to be different.

Q. What effect, if any, do book/tax temporary differences have on the Company's financial statements?

A. If current book/tax temporary differences cause Taxable Income to be lower than Pre-Tax Income, a Deferred Tax Liability will be recorded as part of ADIT because payment of current taxes is being deferred into a future period. If current book/tax temporary differences cause Taxable Income to be higher than Pre-Tax Income, a Deferred Tax Asset will be recorded as part of ADIT because the payment of taxes is being accelerated and lower taxes will be paid in the future.

Q. Why does ADIT need to be revalued when income tax rates change?

A. ADIT represents future taxes payable or receivable. ADIT is calculated as accumulated book/tax temporary differences amounts multiplied by the current federal and state tax rate. If the federal or state tax rate changes, the amount of future taxes payable or receivable will change. For example, if the federal tax rate decreases and ADIT is a liability, the Company will owe less taxes in the future under the lower tax rate. When tax rates change, GAAP requires all ADIT to be revalued to represent future taxes payable/receivable at the tax rate they are expected to be paid/received.

Q. Has the Company revalued all ADIT balances as of December 31, 2017 to reflect a 21% federal tax rate?

A. Yes, the Company revalued all ADIT balances as of December 31, 2017 to reflect a 21% federal tax rate. The corresponding entry to reduce net ADIT Liabilities was recorded as a Regulatory Liability according to FERC guidance, *Docket No. AI93-5-000*. According to FERC guidance, once a utility's ADIT are no longer owed to the government under the new rates and the ADIT balance represents amounts previously collected from customers in utility rates, the Liability for excess ADIT no longer exists and, instead, a Regulatory Liability for the amounts to be returned to customers now exists and will be properly classified that way in the FERC chart of accounts, *Docket No. AI93-5-000*. Please see Exhibit JAG-3 for AI93-5-000 and other FERC guidance documents the Company relied on when revaluing the federal tax rate change.

Q. Please describe how the Company calculated excess ADIT as of December 31, 2017.

A. The Company scheduled out into future periods the timing of the turning of its ADIT balances and reconciled all of its ADIT underlying book/tax temporary differences as of December 31, 2017. Once the underlying book/tax temporary differences were reconciled, the Company adjusted, or "revalued," the federal ADIT accounts at the new federal corporate tax rate.

Q. What is the total amount of excess ADIT calculated by the Company?

A. As shown on Exhibit JAG-5, the total excess ADIT plus gross up calculated by the Company is $16,601,346. These calculations, with gross-up, conform to FERC guidance, Docket No. AI93-5-000. Until this Regulatory Liability is returned to customers it will continue to act as a reduction to rate base.

Q. How will the Company flow back the excess ADIT to ratepayers?

A. The TCJA has identified two methods of flowing back excess ADIT to ratepayers, TCJA §13001(d). If sufficient records exist, the utility is required to use the Average Rate Assumption Method ("ARAM") to flow back excess ADIT to ratepayers. The ARAM formula flows back excess ADIT on an "average" rate as the book/tax temporary differences reverse. If sufficient records do not exist, the Reverse South Georgia Method ("RSGM") is to be used. The RSGM looks at the remaining estimated life of the book/tax temporary difference and reverses on a straight line basis according to the remaining temporary difference life.

Q. Does the Company have sufficient records to utilize the ARAM method?

A. Yes, the Company uses fixed asset software created by PowerPlan, Inc. which tracks book/tax temporary differences and projects the reversal of these temporary differences.

Q. Has the Company performed the ARAM calculation for the excess ADIT?

A. Yes, the Company has performed the ARAM calculation for the excess ADIT. The Company has calculated the flow back period to be 22 years as shown on Exhibit JAG-6. The annual ARAM flow back of the Regulatory Liability amortization credit to expense could have begun on January 1, 2018, but as the Commission explained in Order No. 26,123 in Docket DE 18-036, the Company proposed to resolve the flow back of distribution-related excess ADIT to ratepayers during its next base rate case.

Q. How does the Company propose to flow back the excess ADIT through base distribution rates?

A. The Company is proposing an annual ARAM flow back of $999,795 through base distribution rates as provided in Schedule RevReq-3-18.[1]

Q. How does the Company propose to flow back the excess ADIT related to the 2018-2020 flow back period?

A. As described the in the prefiled testimony of Messrs. Goulding and Nawazelski, the Company is proposing to accelerate the recovery of the current deferral balance of the Company's Major Storm Cost Reserve ("MSCR"), which was materially under-collected at the end of 2020 with an under-recovered balance of $3,275,423. Applying the annual excess ADIT flow back for the years 2018-2020, or $2,664,590, would reduce the Company's MSCR deferral balance to $630,833 as shown in Schedule RevReq-4-5, lines 1-3.

[1] References to Schedule RevReq-3-18 in my testimony are to the RevReq schedules provided in the testimony of UES witnesses Christopher J. Goulding and Daniel T. Nawazelski.

Q. How would this impact the excess ADIT regulatory liability?

A. The flow back of excess ADIT related to the 2018-2020 flow back period described above would reduce the Excess ADIT regulatory liability by $1,928,356, as calculated in Schedule RevReq-4-5, lines 4-6.

IV. PANDEMIC TAX RELIEF PROVIDED IN THE CARES ACT AND THE FFCRA

Q. Briefly summarize the pandemic tax relief enacted in the CARES Act.

A. The CARES Act included tax relief for affected taxpayers. Notably, the relief provisions were primarily temporary suspensions of limitations enacted in the TCJA. The CARES Act made changes to Net Operating Loss ("NOL") Carryback period, NOL carryforward limitations, interest limitation deductibility, Alternative Minimum Tax refunds, extended timeline for first quarter 2020 estimated tax payments and employment related tax credits.

Q. What pandemic tax relief items did the Company utilize?

A. The Company utilized the extended timeline for first quarter 2020 estimated tax payments and one of the employee related tax credits, the Employee Retention Credit ("ERC").

Q. Why didn't the Company utilize the other pandemic tax relief items enacted in the CARES Act?

A. The Company did not have qualifying NOL carryforwards under the CARES Act to utilize the expanded carryback window and also did not have any NOL carryforwards previously limited by the TCJA. Additionally, the Company's interest deductions were not previously limited by the TCJA.

Q. What is the ERC and how did the Company utilize it?

A. The CARES Act enacted the ERC to incentivize companies to retain employees. The ERC is a 50% credit on employee wages for employees that are retained and cannot perform their job duties at 100% capacity as a result of coronavirus pandemic restrictions. The ERC is taken as a credit against employment taxes on Form 941. In the third quarter of 2020, UES and Unitil Service recorded ERCs of approximately $32,511 and $279,213, respectively as reductions to employment tax expense.

Q. What pandemic tax relief was enacted in the FFCRA?

A. The FFCRA provided paid sick leave for employees who had to quarantine, care for a quarantined individual, or care for a child whose school or child care provider is closed or unavailable for reasons related to COVID-19. The FFCRA is taken as a credit against employment taxes on Form 941. In the fourth quarter of 2020, UES recorded an FFCRA of approximately $111,000 as a reduction to employment tax expense.

V. EFFECTS OF THE TCJA ON UTILITY CASH FLOWS AND RATE BASE

Q. What effect does the lower federal income tax rate and the return of excess ADIT to customers have on the Company's cash flows and sources of funding from tax deferrals?

A. Cash flows were decreased in 2018 when the Company reduced the federal income tax rate in its cost of service to 21%. With lower cash flows, the Company must seek external capital and liquidity to replace the decreased government benefit realized through accelerated tax deductions on utility plant capital investments. All else held constant, lower cash flows and higher amount of debt put stress on the Company's credit metrics. The Company's analysis has determined that the lower corporate income tax rate and return of excess ADIT to customers decreases tax deferred funding benefits from the federal government by $0.14 per dollar invested.

Q. How did you calculate the decrease of $0.14 per dollar invested?

A. The $0.14 decreased tax benefit per dollar invested is the difference between the old top corporate income tax rate versus the new top corporate income tax (35%-21%=14%). For each dollar invested, the Company, which is in the top corporate tax rate, loses a 14% tax benefit because of the lower tax rate. This translates to $0.14 per dollar invested.

Q. Do the Company's utility plant assets still qualify for accelerated bonus depreciation?

A. No, utility plant assets no longer qualify for bonus depreciation under the TCJA.

Q. What effect, if any, does the exclusion of utility plant assets from accelerated bonus depreciation have on the Company's cash flows?

A. The Company now receives only 3.75% of the federal income tax benefit for utility plant assets in the year placed in service. Previously when the Company's plant assets qualified for bonus depreciation, it received over 51.875% of the federal tax benefit in the year the assets were placed in service. This also significantly decreases the Company's cash flows and availability of tax deferred funding benefits.

Q. How did you calculate the 3.75% federal tax benefit which the Company now receives in the first year under the TCJA?

A. The 3.75% federal benefit is the first year MACRS depreciation rate the Company is allowed to deduct on its utility plant investments.

Q. How did you calculate the 51.875% federal income tax benefit which the Company was previously allowed to deduct in the first year prior to the TCJA?

A. The 51.875% benefit is a composite rate of the former 50% first year bonus depreciation plus 3.75% of the remaining non-bonus asset basis[2].

Q. What other effects does the TCJA have on the Company's cash flows, rate base, and earned ROCE?

A. All else remaining equal, the Company's rate base will increase at a higher rate between rate cases because its assets no longer qualify for bonus depreciation. This will occur because the associated ADIT offset to rate base will not increase as rapidly year over year due to the exclusion of bonus depreciation. This increased rate base growth has not been as significant in the Company's rate base calculations for over 10 years when bonus depreciation was first enacted in 2002. Absent timely rate relief,

[2] Also computed as 1.875% (3.75% * 50%) on the total asset basis before the bonus depreciation deduction.

the Company's earned ROCE will deviate negatively from its authorized ROE as rate base increases more quickly due to fewer accelerated tax deductions.

VI. CONCLUSION

Q. Does that conclude your testimony?

A. Yes, it does.

Unitil

Tax Cuts and Jobs Act of 2017 (TCJA)

The Effect of Federal Income Tax Changes on Regulatory and Financial Reporting

Unitil Implementation Plan - 2018

Date: July 06, 2018

Table of Contents

Contents

Unitil

EXECUTIVE SUMMARY:

On December 22, 2017 the legislation commonly known as the Tax Cuts and Jobs Act ("TCJA") was signed into law, resulting in the most sweeping changes in US federal income tax rules since 1986. The new law will significantly affect Unitil Corporation's (the "Company") tax returns for 2017 and future years. In addition, many of the Regulatory accounting and Financial Reporting aspects of the new law must be recognized in the Company's GAAP financial statements, beginning in 2017. Most significantly; the new tax law reduces the top marginal corporate tax rate from 35 % to 21 %.

Specifically for regulated public utilities, interest expense continues to be deductible, while bonus depreciation was discontinued. Also, while limiting various deductions, the new law eliminates the corporate alternative minimum tax.

Other changes include:

- Limitations on certain executive compensation deductions
- Limitations on certain deductions for NOLs arising after December 31, 2017 (limited to 80% of taxable income)
- Reduced deductions for meals and entertainment as well as state and local lobbying

The most significant consequence to the Company's December 31, 2017 financial statements was the recognition of a net Regulatory Liability of $48.9MM related to the estimated revaluation/reduction in amount of Accumulated Deferred Income Taxes ("ADIT"), recognized at 34% in previous years, at the new 21% federal corporate tax rate.

From a Regulatory standpoint, and in each of our Federal and State jurisdictions, the immediate issues voiced by our regulators were; 1) when will Unitil reduce its customers' rates for the benefit of the new, lower 21% tax rate, and 2) how and when will Unitil "flow-back" the benefit of the excess ADIT ("EDIT"), which had been recognized previously in customers' rates, to customers.

Unitil

Immediately in Q1, the Company undertook an extensive review and analysis of the EDIT, now a $48.9MM net Regulatory Liability, on its balance sheet in order to complete its 2018 regulatory financial reporting compliance entries and to inform the execution of the Company's Regulatory ratemaking plan.

SUMMARY ANALYSIS:

There are two potential benefits (reductions in customers' rates) which will arise from the implementation of the TCJA: 1) a reduction, as soon as practicable, in customers' rates due to the change in the tax rate to 21% from 34% on the Company's current book/taxable income in 2018 and forward, and 2) a reduction, as soon as practicable, in customers' rates when the Company "flows-back" the benefit of the EDIT which had been recognized previously in customers' rates. The Company distinguishes these EDIT classifications as 'Rate Base EDIT' and 'Non-Rate Base EDIT'. The first reduction is being accomplished rather quickly, in 2018, as new ratemaking calculations are processed in each of the Company's regulatory jurisdictions. According to current law and regulatory accounting guidance; the second reduction, related to ADIT historically included in the Company's rate base for ratemaking calculations, is proposed to flow-back to customers in rates, per FERC NOPR *RM18-11-000*, over a period determined by the Average Rate Assumption Method ("ARAM"), per TCJA Sec. *13001, 131 Stat. at 2096*, projected to be approximately 15-20 years, to be in compliance with the normalization method of accounting described in the Sec. 203(e) of the Tax Reform Act of 1986. [Please refer to APPENDIX A: ASC-740 TCJA IMPLEMENTATION MATRIX].

The Company undertook a detailed analysis of each of the components of EDIT, specifically 25 categories of ADIT in 6 regulatory divisions, which comprise the $48.9MM net Regulatory Liability at December 31, 2017 for the purposes of determining how and when to flow-back EDIT to customers. The return of EDIT to customers was evaluated based on historical ratemaking treatment for the underlying deferred tax items in each jurisdiction. EDIT which had been previously included in customers' rates is identified as "Rate Base EDIT" and all other EDIT is identified as "Non-Rate Base EDIT" for regulatory accounting purposes.

Unitil

Under the normalization method, there is also a classification of “protected” vs “non-protected” ADIT amounts which is consistent with the Company’s distinction of “Rate Base” ADIT which contains protected and non-protected ADIT. The Company’s “Non-Rate Base” ADIT contains only “non-protected” ADIT.

Normalization: is the method of accounting of recording the correct expenses in the periods that they belong to rather than the period in which they occur. An Example is using deferred tax expense on book/tax timing items to keep the ETR near the statutory tax rate over the life of the underlying depreciable asset vs only recording current expense and having the tax expense vary widely year over year according to the MACRS schedule. Protected EDIT (and ADIT): is protected by IRS Normalization rules via Normalization violation penalties. These are mostly related to depreciable assets eligible for accelerated depreciation rates as established with IRC 167 and IRC 168. Unprotected EDIT (and ADIT): is not protected by IRS Normalization rules via Normalization violation penalties. Unprotected EDIT can be either rate base or non-rate base in its treatment.

While the Company will process the reduction to customers’ rates due to the adjustment for Rate Base EDIT in the next divisional rate case proceedings, the Company’s has determined that Non-Rate Base EDIT was generated outside of the ratemaking process and should be treated in accordance with ASC 740-10-55-23. As a result, the Company concludes there is $47.1MM of Rate Base EDIT and $1.8MM of Non-Rate Base EDIT in the total EDIT balance of $48.9MM recognized at December 31, 2017. [Please refer to APPENDIX B: ADIT Tax Rate Revaluation Summary by Division – Rate Base EDIT and Non-Rate base EDIT].

ANALYSIS:

- **RATE BASE EDIT:**

  Rate Base EDIT includes EDIT related to normal Property, Plant and Equipment book/tax temporary differences, plant EDIT, as well as all other non-plant EDIT items with book/tax temporary differences which have been historically included in the utility subsidiaries rate base ratemaking calculations. For the non-plant EDIT amounts, classifying the appropriate amounts as Rate Base EDIT was determined by validating that the various types of non-plant ADIT had been previously included in ratemaking for each regulated jurisdiction. The Company's Tax Manager verified with the Regulatory Department the proper inclusion of the specific EDIT components as Rate Base EDIT.

- Plant Accumulated Deferred Income Tax (ADIT)

Federal ADIT for property, plant and equipment (plant ADIT) relates primarily to tax methods of depreciation (bonus depreciation, MACRS and fixed asset repairs tax deductions) that are accelerated relative to GAAP straight-line depreciation. Immediately prior to the enactment of the TCJA, the deferred tax liability for accelerated tax depreciation methods was calculated based on a 34% federal tax rate. ASC 740 Income Taxes provides guidance requiring that "excess ADIT" be derecognized upon a reduction in tax rates so that ADIT is appropriately measured at the tax rates expected to be in effect when the temporary differences reverse (21%), with an offset to income tax expense from continuing operations. However, given the nature of most of the Company's plant assets as public utility property; the offsetting entry is made to a regulatory liability, in compliance with IRS normalization rules which require that the revaluation adjustment be used to lower customers' utility bills over the remaining lives of property, plant and equipment. The excess ADIT will be flowed back to customers using the Average Rate Assumption Method (ARAM), as discussed further in this memo.

Additionally, the Company revalued its Net Operating Loss Carryforwards (NOLC). Historically the Company has included NOLCs in rate base for its respective utility subsidiaries as a component of utility plant ADIT; therefore, the NOLC was included in the revaluation of recoverable plant ADIT.
Approximately $163MM of plant related ADIT was revalued to arrive at a $48.2MM plant related EDIT adjustment ($66.4 million grossed-up for tax).

The effects to plant ADIT and regulatory liabilities at Dec. 31, 2017 were as follows:

TABLE 1: Plant ADIT Revaluation Effect (Including NOLC)

Debit/(Credit)	**Estimated Balance Sheet ADJ @ 12.31.17**		
Utility Subsidiary	Long-Term Deferred Income Taxes	Regulatory Gross-Up	Long-Term Regulatory Liabilities
UES	$ 16,614,471	$ 6,220,465	$ (22,834,936)
NUNH	6,639,969	2,486,007	(9,125,976)
NUME	8,898,999	3,470,119	(12,369,118)
FGE_E	7,236,950	2,720,328	(9,957,278)
FGE_G	7,583,498	2,850,594	(10,434,092)
GSGT	1,208,479	452,455	(1,660,934)
Total Plant EDIT Adjustment	**$ 48,182,366**	**$ 18,199,968**	**$ (66,382,334)**

- *Non-Plant ADIT included in Rate Base*

Similar to excess plant ADIT, an adjustment was required in the Q4 2017 period of enactment to derecognize excess non-plant ADIT such that ADIT is appropriately measured at the tax rates expected to be in effect when the temporary differences reverse (21%). For the non-plant ADIT revaluations, determining the appropriate amounts of net ADIT assets/liabilities to adjust to regulatory assets/liabilities was determined based on whether the various types of non-plant ADIT had been previously included in ratemaking for each regulated jurisdiction. See further

Unitil

discussion below. Approximately $2.2MM of Non-Plant ADIT in Rate Base were revalued to arrive at a $1.0MM Non-Plant plant related EDIT adjustment ($1.4 million grossed-up for tax). The regulatory asset balance was primarily driven by the revaluation of employee benefits.

The effects to recoverable non-plant ADIT and regulatory liabilities at Dec. 31, 2017 were as follows:

Table 2: Non-Plant Recoverable ADIT Revaluation Effect

Debit/(Credit)	**Estimated Balance Sheet ADJ @ 12.31.17**		
Utility Subsidiary	Rate Base Deferred Income Taxes	Regulatory Gross-Up	Long-Term Regulatory Asset/(Liability)
UES	$ (343,638)	$ (128,658)	$ 472,296
NUNH	(246,628)	(92,338)	338,966
NUME	(283,332)	(110,484)	393,816
FGE_E	(100,722)	(37,861)	138,583
FGE_G	(80,015)	(30,077)	110,092
GSGT	12,803	4,793	(17,596)
TOTAL EDIT ADJUSTMENT	**$ (1,041,532)**	**$ (394,625)**	**$ 1,436,157**

As a result, the Company concludes there is $48.2MM of Plant related Rate Base EDIT and ($1.1MM) of Non-Plant related EDIT in the total Rate Base EDIT balance of $47.1MM, before gross-up, recognized at December 31, 2017. [Please refer to APPENDIX B: ADIT Tax Rate Revaluation Summary by Division – Rate Base EDIT and Non-Rate base EDIT].

- **NON-RATE BASE EDIT:**

  Non-Rate Base EDIT relates to other book/tax temporary differences that never were previously recovered in utility rates. These include EDIT related to accrued revenue and storm reserve book/tax temporary differences as well as all other non-plant EDIT items with book/tax temporary differences which were historically excluded in that division's base rate ratemaking calculations. For the non-rate base EDIT amounts, classifying the appropriate amounts as Non-Rate Base EDIT was determined by validating that the various types of non-rate base ADIT had been previously excluded in ratemaking for each utility subsidiary. The Company's Tax Manager verified with the Regulatory Department the proper exclusion of the specific EDIT components as Non-Rate Base EDIT.

- *Non-Rate Base ADIT*

  While the Company will process the reduction to customers' rates due to the adjustment for Rate Base EDIT in the next rate case proceeding for each utility subsidiary, the Company's has determined that Non-Rate Base EDIT was generated outside of the ratemaking process and should be treated in accordance with ASC 740-10-55-23. As a result, the Company concludes there is $1.8MM of Non-Rate Base EDIT in the total EDIT balance of $48.9MM recognized at December 31, 2017. [Please refer to APPENDIX B: ADIT Tax Rate Revaluation Summary by Division – Rate Base EDIT and Non-Rate base EDIT and APPENDIX B-1: Non-Rate Base EDIT Schedule]. The Company will record the revaluation in its Statement of Earnings for the twelve months ended December 31, 2018; recognized ratably over the 2018 quarterly reporting periods. See below SAB 118 discussion and the Company's 2018 FIN 18 Memo for further discussion.

Unitil

Non-Rate Base ADIT revaluation that will be recorded as of December 31, 2018 is comprised as follows:

Non-Rate Base Revaluation Effect

Debit/(Credit)	Balance Sheet	Income Statement
	Non-Recoverable Income Taxes	**Deferred Tax Provision**
UES	$ 839,574	$ (839,574)
NUNH	(178,638)	178,638
NUME	114,653	(114,653)
FGE_E	943,366	(943,366)
FGE_G	60,086	(60,086)
GSGT	353	(353)
TOTAL	**$ 1,779,394**	**$ (1,779,394)**

Key Non-Rate Base components are as follows:

- *Accrued Revenue*: The Company has many regulatory tracker mechanisms; the largest include purchases of gas and electric supply for customers in its regulated jurisdictions. These energy supply costs are charged without markup to customers throughout the year. The accrued revenue position on the Company's balance sheet changes seasonally during the year according to the heating/cooling season. Because the accrued revenue on the Company's balance sheet turns multiple times in a year the regulatory precedent has been to keep the tax effect out of the regulatory ratemaking process.

Unitil

At December 31, 2017 the Company had an accrued revenue receivable related to the upcoming heating season which created 2017 current tax deductions which were recognized at 34%. However, the associated revenue receivables collected in 2018 will be paid in 2018 and taxed at 21%.

- *Contributions In Aid of Construction (CIAC):* Utility plant assets funded by contributions from sources outside of regulated ratemaking have always had $0 capital value and are excluded from the regulatory process. However, the funds received are included in taxable income and create ADIT which will reverse in future periods as the Company refunds or depreciates CIAC. This ADIT is funded by the Company outside of regulatory ratemaking.

- *Storm Restoration:* The Company recovers qualifying storm costs from ratepayers. While the carrying charge calculation includes certain tax attributes, the associated ADIT from storm expenditures and collections has been historically excluded from regulated ratemaking and funded by the Company.

- *Acquisition Costs*: Acquisition costs and the associated deferred tax assets/liabilities are borne by the Company. Ratepayer cost neutrality is always achieved in rate regulated utility mergers/acquisitions. Therefore, the Company classifies the ADIT associated with acquisition costs as Non-Rate base.

- *Remediation*: Certain activities engaged in by the Company require environmental remediation. While these costs are funded through the ratemaking process the associated ADIT is funded by the Company and all tax benefits are retained by the Company under the respective utility subsidiary cost recover agreements.

- *Other Book/Tax Differences*: The Company has various other miscellaneous deferred tax assets and liabilities that are funded by the Company outside of the regulatory ratemaking process and include: prepaid property taxes, bad debts, rate case costs, insurance settlements, and integrity management programs.

As a result, the Company concludes there is a net $47.1MM, before gross-up, of Rate Base EDIT and $1.8MM of Non-Rate Base EDIT in the total EDIT balance of $48.9MM recognized at December 31, 2017. [Please refer to APPENDIX B: ADIT Tax Rate Revaluation Summary by Division – Rate Base EDIT and Non-Rate base EDIT and APPENDIX B-1: Non-Rate Base EDIT Schedule]. The Company will record the revaluation in its Statement of Earnings for the twelve months ended December 31, 2018. See below SAB 118 discussion and the Company's 2018 FIN 18 Memo for further discussion.

- **Other Effects & Evaluations**

  - **Securities and Exchange Commission Staff Accounting Bulletin 118 ("SAB 118")**

    On Dec. 22, 2017, the SEC staff issued SAB 118 to address the application of US GAAP in situations in which the necessary information is not available, prepared, or analyzed (including computations) in reasonable detail to complete the book accounting for the TCJA.

    The Company has determined reasonable estimates of the effects of the TCJA, and recognized the estimates in its financial statements for the year ended Dec. 31, 2017, but notes that given expected changes to U.S. Treasury regulations, interpretations of the TCJA by the U.S. Treasury or IRS, interpretations of the application of ASC 740, and developing regulatory guidance and orders these estimates are subject to change.

    Specifically, the Company made an estimate at year-end 2017 to the Balance Sheet and P&L effects of the ADIT revaluation. However, in the first quarter of 2018 the Company participated in conference calls with other New England utilities, reviewed all regulatory mechanisms, began preparing regulatory filings, and started regulatory discussions with certain regulatory jurisdictions. The result of this process was the identification of certain ADIT for which estimates were adjusted to conform to general regulatory ratemaking principles.

- **Expected 2018-Forward Effects**

  Overall, since income tax expense is a significant rate-recovered cost for regulated utilities, many state public utility commissions and other stakeholders are expecting significant reductions in cost based rates as a result of the new tax law. The specific effects of the TCJA on retail customer rates are subject to regulatory approval. The Company is in the process of quantifying the rate effects of the TCJA and addressing these effects in its open and recently concluded proceedings focused on retail base rate effects for its utility subsidiaries. In addition, several states have opened dockets on the effect of tax reform, with the expectation that currently effective rates in those jurisdictions will be adjusted. The Company expects to "true-up" the initial estimates made at December 31, 2017 at the end of the first quarter in 2018 and forward as the utility subsidiary regulatory processes play out.

PURPOSE:

The purpose of this memo is to document Unitil's TCJA Implementation Plan accounting considerations for the significant elements of the TCJA that were recognized as a component of financial reporting for income taxes (book accounting) in the year ended December 31, 2017 and will be recognized in the year ended December 31, 2018.

ACCOUNTING GUIDANCE:

ASC 740 *Income Taxes*
PWC *Guide to Income Taxes*
FERC *NOPR RM18-11-000*

UNITIL CORPORATION'S 2018 TCJA IMPLEMENTATION PLAN:

[Please refer to APPENDIX C: UNITIL CORPORATION'S TCJA IMPLEMENTATION PLAN].

DISCUSSION:

ASC 740 Guidance: Applying New Tax Rates to ADIT as of the Enactment Date

While the reduction in the corporate tax rate from 34% to 21% will result in an overall reduction in income tax expense going forward, a discrete adjustment must also be made in the period of enactment to adjust ADIT to reflect the lower income tax rate that will apply when the temporary differences reverse. The enactment date in the U.S. federal jurisdiction is the date the President of the United States signs a tax bill into law. The TCJA was signed into law by President Trump on December 22, 2017.

ASC 740-10-55-23 states:

> The tax rate or rates that are used to measure deferred tax liabilities and deferred tax assets are the enacted tax rates expected to apply to taxable income in the years that the liability is expected to be settled or the asset recovered.

For Non-Regulated Companies for example, a reduction in an ADIT liability would be recorded by measuring temporary differences at the new statutory income tax rate (i.e., 21%), and comparing this result to the ADIT balance existing prior to the effective date of the income tax reduction, resulting in the following journal entry:

Dr. Deferred Tax Liabilities B/S

Cr. Deferred income tax expense P&L

To re-measure a Non-Regulated Company's ADIT for a change in tax rate upon the enactment date.

For regulated companies however, the rate base ADIT is funded by ratepayers through base rates and any adjustments should be flowed back to ratepayers. Therefore, instead of adjusting ADIT through an adjustment to deferred income tax expense, the accounting for effects of the tax rate reduction expected to be collected or shared with ratepayers would follow ratemaking, resulting in recognition of regulatory assets and regulatory liabilities.

The entry to record a reduction in an ADIT liability for a rate regulated utility is as follows:

Dr. Deferred Tax Liabilities B/S
Cr. Regulatory Liabilities B/S

To re-measure ADIT for a change in tax rate upon the enactment date.

Determination of the discrete effect of the rate change using year-end (i.e., December. 31, 2017) temporary differences is an acceptable practice as the temporary differences are expected to approximate the deferred tax balances as of the enactment date. Material unusual or infrequent transactions occurring between the enactment date and year-end will need to be taken into consideration. However, common practice allows the discrete effect to be calculated on year-end balances which will be calculated in the Company's tax accrual at the old rate.

Regulatory Accounting Journalizing techniques for UNITIL'S 2018 TCJA IMPLEMENTATION PLAN:

There are five sets, see below, of journal entries related to Unitil's implementation of the TCJA for regulatory accounting purposes to recognize the following three events:

A. Recognize the revenue and tax provision reductions in current utility rates to reflect the benefit to customers of the Federal income tax rate change from 34% to 21% either into current billing or on a deferral basis as indicated by the Regulators. Recognize gross up entries as appropriate.

Unitil

B. Recognize the amount and timing of the revenue reduction in future utility rates to reflect the amortization of the flow-back of excess ADIT at December 31, 2017 as a benefit to customers due to the Federal income tax rate change from 34% to 21% on the valuation of net deferred tax liabilities which were previously collected in rates. Recognize gross up entries as appropriate.

C. Recognize the amount of the reduction in the Company's current 2018 tax provision to reflect the revaluation of excess ADIT at December 31, 2017 as a one-time benefit to the Company due to the effect of the Federal income tax rate change from 34% to 21% on the valuation of net deferred tax liabilities which were never previously collected in rates, and thus ineligible for deferral as discussed below.

A portion of the 2017 effect of the TCJA relates to revaluation of Non-Rate Base ADIT at the reduced corporate federal income tax rate. ASC 740 requires that adjustments to ADIT upon a tax rate change be recorded to income tax expense/benefit from continuing operations, however, it was necessary for the Company's regulated utility subsidiaries to consider whether each of the Non-Rate Base ADIT revaluation adjustments should be collected from or refunded to customers, similar to refunds due customers for the revaluation of plant ADIT, and therefore deferred to regulatory assets and liabilities.

For the Non-Rate Base ADIT revaluations, determining the appropriate amounts of income tax expense/benefit to defer to regulatory assets/liabilities was performed in a two-step process. First, the Company considered whether the various types of Non-Rate Base ADIT had been previously included in ratemaking for each regulated jurisdiction. If an element of Non-Rate Base ADIT had been included in ratemaking for that utility subsidiary jurisdiction, the valuation adjustment was deemed eligible for deferral as a regulatory asset or liability, reflective of an expectation to share the adjustment with ratepayers in future rates. If the element of Non-Rate Base ADIT had not historically been included in ratemaking for the applicable utility subsidiary jurisdiction, the resulting income tax expense/benefit was not eligible for deferral and will be recorded to income tax expense/benefit from continuing operations in 2018.

Unitil

Rate regulated utilities additionally need to take into consideration the provisions of ASC 980 and the rate treatment of tax rates as outlined in ASC 980-740-25-1 and 2:

> For regulated entities that meet the criteria for application of paragraph 980-10-15-2, this Subtopic specifically:
>
> a. Prohibits net-of-tax accounting and reporting
> b. Requires recognition of a deferred tax liability for tax benefits that are flowed through to customers when temporary differences originate and for the equity component of the allowance for funds used during construction
> c. Requires adjustment of a deferred tax liability or asset for an enacted change in tax laws or rates
>
> If, as a result of an action by a regulator, it is probable that the future increase or decrease in taxes payable for items (b) and (c) in the preceding paragraph will be recovered from or returned to customers through future rates, an asset or liability shall be recognized for that probable future revenue or reduction in future revenue pursuant to paragraphs 980-340-25-1 and 980-404-25-1. That asset or liability also shall be a temporary difference for which a deferred tax liability or asset shall be recognized.

Therefore and also initially, a gross-up amount will be calculated on the Regulatory Liability and recognized in deferred tax assets so that this gross-up amount will be available to turn against the deferred tax provision entry recognized in future periods as the Regulatory Liability is amortized into pre-tax book income and scheduled in that period's tax provision calculations as a temporary difference.

There are five sets, itemized below, of journal entries related to the Company's implementation of the TCJA for regulatory accounting purposes to recognize the three events noted above:

A. Recognize the revenue and tax provision reductions in current utility rates to reflect the benefit to customers of the Federal income tax rate change from 34% to 21% either into current billing or on a deferral basis as indicated by the Regulators. Recognize gross up entries as appropriate.

   1. When the effect of the TCJA tax rate change is reflected in customer rates, then revenue will be reduced for the Company and its tax provision will also be reduced and no further entries are required for this item. As of March 31, 2018 this is the case for NUME, and it is expected to be the case for GSGT in August 2018.

   2. Until item #1 above occurs, and if the regulator has indicated an expectation of the tax rate change effect on current utility rates to be effective January 1, 2018: then the Company will make the following accrual, in addition to reducing its current tax provision, until the new rates are effective. As of March 31, 2018 this is the case for all the Company's utility subsidiaries except NUME and GSGT.

      DR. Accrued Revenue P&L
      DR. Deferred Tax Asset (gross-up on regulatory liability) B/S
      CR. Regulatory Liability B/S

      To recognize a Regulatory Liability for the customer's benefit of the change in TCJA tax rate, effective January 1, 2018, and including a gross-up factor, which will be included in customer rates in an agreed upon future rate proceeding.

Unitil

B. Recognize the amount and timing of the revenue reduction in future utility rates to reflect the amortization of the flow-back of excess ADIT at December 31, 2017 as a benefit to customers due to the Federal income tax rate change from 34% to 21% on the valuation of net deferred tax liabilities which were previously collected in rates. Recognize gross up entries as appropriate.

3. First, set up the entry to correct the Company's Rate Base ADIT for the revaluation of these liabilities at the new lower TCJA tax rate which will be amortized and flowed-back to customers, over the ARAM period, incompliance with the IRS normalization rules and the jurisdictions regulatory ratemaking process:

DR. ADIT B/S
DR. Deferred tax asset (gross-up on regulatory liability) B/S
CR. Regulatory Liability B/S

To recognize a Regulatory Liability for the effect the change in TCJA tax rate on ADIT previous collected in utility rates, including a gross-up factor, which will be a reduction in customer rates in an agreed upon future rate proceeding.

4. Second, in future periods this Regulatory Liability for EDIT will be amortized and flowed-back to customers, over the ARAM period, in compliance with the IRS normalization rules and the utility subsidiary regulatory ratemaking process. In those periods the entry will be:

DR. Regulatory Liability B/S
DR. Deferred Tax Provision P&L
CR. Deferred Tax Asset (gross-up on regulatory liability) B/S
CR. Regulatory Liability Amortization P&L

Unitil

To recognize the Amortization of the Regulatory Liability set up for the effect the change in TCJA tax rate on ADIT previously collected in utility rates, including a gross-up factor, which will be a reduction in customer rates in this future period as determined in a future rate proceeding.

C. Recognize the amount of the reduction in the Company's current 2018 tax provision to reflect the revaluation of excess ADIT at December 31, 2017 as a one-time benefit to the Company due to the effect of the Federal income tax rate change from 34% to 21% on the valuation of net deferred tax liabilities which were never previously collected in rates, and thus ineligible for deferral as discussed below.

5. In current quarterly periods, this entry will be recognized due to the effect of the Federal income tax rate change from 34% to 21% on the valuation of No-Rate Base net deferred tax liabilities which were never previously collected in rates:

DR. ADIT B/S

CR. Deferred Tax Provision P&L

To recognize the effect of the Federal income tax rate change from 34% to 21% on the valuation of Non-Rate Base net deferred tax liabilities which were never previously collected in rates.

ASC 740 Guidance: Use of a Gross-Up Factor in Reversing Excess ADIT

Rate regulated utilities do not use ASC 740 for determining deferred income tax expense, rather deferred income tax expense is calculated on a 'with and without' basis. Income tax expense is compared 'with' book/tax timing differences to what the expense would be 'without'. Under rate regulation, a revenue requirement is computed applying a test period reflective of costs expected to be incurred when rates are effective. A rate case includes the costs to provide the utility service, including rate base (net property, plant and equipment, working capital and a reduction for ADIT). The rate base is multiplied by a rate of return, resulting in an operating income requirement, which is combined with the operating costs necessary to provide service to customers. Operating expenses include operating and maintenance costs, depreciation, income taxes and taxes other than income taxes. The operating income requirement plus operating expenses equals the revenue requirement.

The entry to reflect a reduction in tax rates for rate regulated entries is computed at the revenue requirement (gross-up) level and reflects the probability that a reduction in ADIT will reduce customer rates and that the regulatory liability itself is a temporary difference. Thus, the re-measurement of a deferred tax liability results in the following entry:

DR. ADIT B/S
DR. Deferred tax asset (gross-up on regulatory liability) B/S
    CR. Regulatory liability B/S

To re-measure regulated Deferred Tax Liabilities upon a change in tax rate including a gross-up factor for reversing excess ADIT

When the Company flows back EDIT to rate payers, the Company will reduce the regulatory liability by recording pre-tax regulatory amortization for the grossed up ARAM amount [see below ARAM discussion]. The regulatory amortization will be treated as a timing difference in the Company's tax provision and normalized by the deferred tax asset (gross-up on regulatory liability). See Appendix D for ARAM normalization gross-up example.

Plant ADIT & ARAM

The application of accelerated depreciation provisions (i.e., bonus depreciation and MACRS accelerated depreciation) provided for within the internal revenue code (IRC) prior to the enactment of the TCJA, created a significant timing difference between book and tax depreciation of property, plant and equipment. Accelerated depreciation results in the reduction of income tax expense in the periods in which accelerated depreciation exceeds book depreciation and conversely results in the increase of income tax expense in the periods in which book depreciation exceeds tax depreciation. Bonus depreciation serves as

Unitil

an incentive to tax payers who can use the deduction to reduce the cost of construction/investment.

To ensure that deferred income tax expense is not excluded as a cost in the ratemaking process, the IRC contains 'normalization provisions' for 'public utility property,' preventing regulators from assigning the benefits of accelerated depreciation to ratepayers [Please refer to APPENDIX H: IRS PLR]. Normalization rules do require that the resulting ADIT be used to reduce rate base or be treated as zero cost capital in the rate of return calculation, providing ratepayers the time value benefit. A normalization violation can result in a regulated entity being prohibited from claiming accelerated depreciation. The normalization provisions apply to accelerated depreciation, certain excess ADIT due to reductions in income tax rate and to the investment tax credit. This method was recently confirmed in FERC Docket RM18-11-00. The Company has determined that this treatment applies to all of its utility plant excess ADIT.

According to recently published FERC guidance [Please refer to APPENDIX I: FERC NOPR pp 4, paragraph 7 (emphasis added)],

> *7. The tax rate reduction will also result in a reduction in accumulated deferred income taxes (ADIT) on the books of rate-regulated companies. The amount of the reduction to ADIT that was collected from customers but is no longer payable to the IRS is excess ADIT and* ***should be flowed back*** *to ratepayers under* ***general ratemaking principles****. The Tax Cuts and Jobs Act does not prevent such flow back, although it does include rules on how quickly companies may reduce their excess ADIT. Specifically, the Tax Cuts and Jobs Act indicates that rate-regulated companies generally should use the* ***average rate assumption method*** *when flowing excess ADIT back to customers. Rate-regulated companies must follow this requirement to be considered* ***in compliance with normalization.*** *Any flow back of ADIT faster than the requirement imposed by*

the Tax Cuts and Jobs Act (e.g., a one-time large credit to ratepayers or a flow-back method that is over a relatively short period of time) would constitute a normalization violation and may result in unfavorable tax consequences.

Treatment of excess ADIT with respect to normalization pertaining to the difference caused by a reduction in the tax rate was first addressed within the 1986 tax act. Under the TCJA, if for any taxable year ending after the date of enactment, a normalization method of accounting is not applied, the tax for the taxable year shall be increased by the amount by which it reduces its excess tax reserve more rapidly than permitted under a normalization method of accounting.

Several Private Letter Rulings from the Internal Revenue Service ("IRS") reference the proper application of the normalization rules. The Internal Revenue Code ("IRC") contains 'normalization provisions' for 'public utility property,' preventing regulators from assigning the benefits of accelerated depreciation to ratepayers [Please refer to APPENDIX H: IRS PLR-155208-06, pp.4-5., issued July 20, 2007].

According to section 203(e)(1) of the Act, a normalization method of accounting shall not be treated as being used with respect to any public utility property for purposes of section 167 or 168 of the Code if the taxpayer , in computing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, reduces the excess tax reserve more rapidly or to a greater extent that this reserve would be reduced under the average rate assumption method (ARAM)…

Section 203 (e) of the Act limits the rate at which the excess tax reserve may be reduced and flowed through to the utility's customers in setting rates. It does not require the utility to flow through the excess tax reserve to its customers, but permits the utility to do so provided the reduction to cost of service is not more rapidly than would be under the ARAM. Thus, section 203 (e) of the Act imposes a limitation on when the excess tax reserve may be returned to the utility's customers in the form of reduced rates.

The required method [Please refer to APPENDIX J: TCJA ARAM] to reduce excess ADIT is referred to as the Average Rate Assumption Method (ARAM). The ARAM method reduces the excess tax reserve over the remaining regulatory lives of the property that gave rise to the reserve for deferred taxes during the years in which the deferred tax reserve related to such property is reversing.

Under this method, the excess tax reserve is reduced as the timing differences (i.e., differences between tax depreciation and regulatory depreciation with respect to the property) reverse over the remaining life of the asset. The reversal of timing differences generally occurs when the amount of the tax depreciation taken with respect to an asset is less than the amount of the regulatory depreciation taken with respect to the asset. To ensure that the deferred tax reserve, including the excess tax reserve, is reduced to zero at the end of the regulatory life of the asset that generated the reserve, the amount of the timing difference which reverses during a taxable year is multiplied by the ratio of (1) the aggregate deferred taxes as of the beginning of the period in question to (2) the aggregate timing differences for the property as of the beginning of the period in question.

In the event a utility did not recognize depreciation on a group basis or if it did not have the historical records to support the reversal of book/tax differences, an alternative method is allowed, a common method being the Reverse South Georgia Method (RSGM). The difference between ARAM and RSGM is the timing of reversal, in that as the utility is unable to determine the depreciation turnaround, excess ADIT is spread ratably over the estimated book life. Both methods result in the application of excess ADIT to reduce customer rates; the reduction begins immediately under application of the RSGM on a straight-lined basis versus the reduction in rates not occurring until reversal of the book/tax difference under the ARAM method. The Company maintains its book and tax asset databases in PowerPlant and PowerTax (PowerPlan software modules) and has the requisite historical information available to apply the ARAM method for the reversal of excess ADIT, and will process the flow back for plant ADIT on this basis.

Rate Base and Non-Rate Base ADIT

An additional significant portion of the 2017 effect of the TCJA relates to revaluation of Non-Rate Base ADIT at the reduced corporate federal income tax rate. ASC 740 requires that adjustments to ADIT upon a tax rate change be recorded to income tax expense/benefit from continuing operations, however, it was necessary for the Company's regulated utility subsidiaries to consider whether each of the revaluation adjustments should be collected from or flowed back to customers, similar to flow back to due customers for the revaluation of plant ADIT, and therefore deferred to regulatory assets and liabilities.

For the Non-Rate Base ADIT revaluations, determining the appropriate amounts of income tax expense/benefit to defer to regulatory assets/liabilities was performed as follows: the Company considered whether the various types of Non-Rate Base ADIT had been previously included in ratemaking for each regulated utility subsidiary. If an element of non-plant ADIT had been included in ratemaking for that utility subsidiary (Rate Base ADIT), the valuation adjustment was deemed eligible for deferral as a regulatory asset or liability, reflective of an expectation to share the adjustment with ratepayers in future rates. If the element of Non-Rate Base ADIT had not historically been included in ratemaking for the applicable utility subsidiary (Non-Rate Base ADIT), the resulting income tax expense/benefit was not eligible for deferral.

While the Company asserts that this analysis achieves a base deferral amount properly grounded in historical ratemaking and the concepts set forth in ASC 740-980-25-2, the recognition of these regulatory assets and liabilities requires that the Company consider whether 100 % continued adherence to past ratemaking treatment of ADIT amounts is reasonably assured in all jurisdictions. Recognizing that the regulatory processes to adjust rates for the TCJA with each regulator (and intervenors) in each jurisdiction will provide parties the opportunity to scrutinize the recovery of costs and the sharing of benefits associated with the TCJA, as well as the types of ADIT included and excluded from rate base in general, the Company determined from conversations with other utilities in their regulatory jurisdictions and their analysis of rate recovery mechanisms that non-plant ADIT classified by the Company as Non-Rate Base ADIT were clearly excluded from the rate making process. Therefore, the Company will not record any associated reserves relating to the recognition of Non-Rate Base ADIT in the Company's 2018 Consolidated Statement of Earnings.

2018 Effects

The Company has calculated its effective tax rate for the period ended December 31, 2018 according to financial accounting standards FIN 18 at 23.34%. This analysis considered the effect of Non-Rate Base EDIT of $1.8MM and changes in the deductibility of certain items discussed below.

[Please refer to Appendix G for the Company's 2018 FIN 18 analysis including all 2018 P&L effects of the TCJA]

Regulated Rates

In January 2018 the Company received notice from its three regulatory jurisdictions to file information related to rate decreases reflective of the lower corporate tax rate. Due to current rate cases and regulatory orders the Company's ratepayers will receive the benefit of lower rates as of January 1, 2018. However, two of the Company's subsidiaries (NUME and GSG) have varying effective dates for lower rates. [Please refer to APPENDIX A: ASC-740 TCJA IMPLEMENTATION MATRIX] NUME was currently in a rate case when the TCJA was signed into law with rates effective March 1, 2018. As a result, NUME will collect lower revenue beginning March 1, 2018; but not before. Additionally, GSG is FERC regulated without a retroactive rate provision. GSG's rates reflecting the lower corporate tax rate are projected to be effective August 1, 2018 and will collect rates reflecting a lower corporate rate beginning on that date; but not before. The Company expects to recognize an after tax benefit of $0.7 MM [Please refer to Appendix F] as a result of the delayed effective dates for NUME and GSG. In addition, the non-rate base EDIT benefit of $1.8MM will also be recognized in 2018 ratably over each quarter according to the Company's 2018 FIN 18 effective Tax Rate calculation.

While the Company's subsidiaries (FGE_E, FGE_G, NUNH and UES) will reduce book billed revenue starting January 1, 2018, the required reduction to base rates are expected to begin at varying times throughout 2018. To account for the retro-active rate reduction, the Company will book a regulatory liability for the amount of the estimated billed revenue reduction recorded prior to the base rate reduction. This regulatory liability will be a book/tax timing difference when flowed back to ratepayers. The Company will record a regulatory gross up for the billed rate reduction to offset the tax effect of the rate reduction regulatory liability. The regulatory liability and gross up will result in the following entry:

DR. Accrued Revenue – TCJA Revenue Reduction P&L
DR. Regulatory Gross-Up – TCJA Revenue Reduction B/S
CR. Regulatory Liability – TCJA Revenue Reduction B/S

To record the regulatory liability and gross up for the required revenue reduction that is not in current base rates.

See Appendix E – Rev Reduction Normalization Gross-Up for an example on how the Company will use a regulatory gross-up to normalize income taxes for rate making purposes.

Treatment of NOLs

Deferred tax assets associated with NOLCs are required to be re-measured to reflect the lower income tax rate expected to be in effect when the temporary differences reverse, with the resulting adjustment of ADIT reflected in continuing operations as a discrete adjustment in the period of enactment.

As a result of the TCJA, NOLCs arising after December 31, 2017 may be used to offset up to 80% of taxable income, without any ability to carryback NOLCs to prior tax years. Unused NOLCs can be carried forward indefinitely. NOLCs generated in tax years beginning before January 1, 2018 are not subject to the taxable income limitation and continue to have a two year carryback and 20 year carryforward period.

Tax-planning strategies under ASC 740 (actions an entity would take to prevent an operating loss or tax credit carryforward from expiring unused), will be effected; NOLs generated after December 31, 2017 will not be subject to expiration. As deferred taxes are scheduled at the new rate, consideration will need to be given to the ability to realize of DTAs. The Company has determined that its NOLCs were generated by bonus depreciation deductions and will not continue to be generated under the TCJA disallowance of utility plant asset bonus depreciation. Therefore, the Company has not recorded valuation allowances for its NOLCs.

Meals and Entertainment

Under current law, up to 50% of expenses relating to meals and entertainment are deductible. Housing and meals provided for the convenience of the employer on the business premises of the employer are excluded from the employee's gross income. Various other fringe benefits provided by employers are also not included in an employee's gross income, such as qualified transportation fringe benefits.

Under the TCJA, deductions for entertainment expenses are disallowed for amounts incurred or paid after Dec. 31, 2017. The current 50% limit on the deductibility of business meals is expanded to meals provided through an in-house cafeteria or otherwise on the premises of the employer; and deductions for employee transportation fringe benefits (e.g., parking and mass transit) are denied, but the exclusion from income for such benefits received by an employee is retained. In addition, no deduction is allowed for transportation expenses that are the equivalent of commuting for employees (e.g., between the employee's home and the workplace), except as provided for the safety of the employee.

For tax years beginning after Dec. 31, 2025, the TCJA will disallow an employer's deduction for expenses associated with meals provided for the convenience of the employer on the employer's business premises, or provided on or near the employer's business premises through an employer-operated facility that meets certain requirements. The change in the deductibility of meals and entertainment is anticipated to result in an increase in tax expense to The Company of approximately $0.01 million.

Unitil

Lobbying

Under current law, ordinary and necessary expenses paid or incurred in connection with carrying on any trade or business are generally deductible. Under pre-Act law, an exception to the general rule, however, disallows deductions for lobbying and political expenditures with respect to legislation and candidates for office, except for lobbying expenses with respect to legislation before local government bodies. The TCJA eliminates the deduction for lobbying expense associated with legislation before local government bodies.

Executive Compensation (Section 162m)

While the TCJA retains the $1 million deductible compensation limitation to covered employees, it eliminates the current exception for performance-based compensation while expanding the covered employee definition. Covered persons will now include the principal executive officer, principal financial officer and three other highest paid officers. Additionally, once an individual becomes a covered person, they will remain a covered person in future years. The changes do not apply to compensation subject to a written binding contract which was in effect on Nov. 2, 2017 and was not modified in any material respect after that date.

As a result of the including performance-based compensation and expanding the covered employee definition, less compensation will be deductible, resulting in an increase in tax expense to The Company of approximately $0.2 million.

Additionally, the TCJA reduces the top individual tax rate to 37%, potentially effecting equity classification for share-based payment awards. In order to avoid liability classification of share-based payment awards currently classified as equity, withholdings will need to be adjusted so as not to exceed 37% in 2018. Based on discussion with the Human Resource Department, withholding on share-based awards settled in 2018 will occur at the 28% supplemental income rate.

Unitil

CIAC

Contributions in Aid of Construction (CIAC) represent contributions of cash by a developer that may or may not be subject to refund. Refundable CIAC (referred to as a customer advance) is treated as a liability until such time as the funds are no longer refundable. CIAC is typically related to distribution line extensions to a new subdivision, condominium, or rural customer for either electric or gas service. Once all opportunity for refund has been eliminated, the legal obligation is satisfied. When the contract is no longer refundable, the remaining construction payment is credited to plant in-service.

Contributions in aid of construction (CIACs) are generally taxable, but there were exceptions, such as generation interconnections and certain payments by government entities. Beginning in 2018, contributions by governmental entities or civic groups (other than a contribution made by a shareholder) shall be treated as taxable CIACs. However, contributions made by governmental entities pursuant to master development plans that were approved prior to December 22, 2017 continue to qualify for the exception.

Some payments from governmental entities that were previously excluded from taxable income will now be taxable. Examples include payments to replace overhead conductor with underground cable near a park. The overall effect of this provision is that gross-up payments for more CIACs may be required.

Significant Items Unchanged

Interest expense deductions are generally limited under the TCJA to 30% of adjusted taxable income (earnings before interest, taxes, depreciation and amortization), with any disallowed interest subject to an indefinite carryforward. The limitation on interest expense deductions does not apply to regulated utilities. Recent initial IRS interpretations of utility interest deductibility have been favorable to utility holding company interest. The Company expects to have minimal impact from proposed and final regulations.

Production Tax Credits (PTCs) and Investment Tax Credits (ITCs) were not affected by the TCJA. The original House bill included provisions that would have eliminated the inflation adjustment for PTCs and removed the permanent 10% ITC for solar and geothermal projects after 2027. In the final enacted TCJA, no changes were made to the tax treatment of PTCs or ITCs, including the existing phase out schedules.

Please refer to Appendix G for the Company's 2018 FIN 18 analysis including all 2018 P&L effects of the TCJA.

Other Areas of Implementation

Staff Accounting Bulletin No. 118 (SAB 118)

On Dec. 22, 2017, the SEC staff issued SAB 118 to address the application of US GAAP in situations in which the necessary information is not available, prepared, or analyzed (including computations) in reasonable detail to complete the book accounting for the TCJA. SAB 118 provides guidance for SEC registrants under the following three scenarios: I) measurement of income tax effects is complete, 2) measurement of income tax effect can be reasonably estimated and 3) measurement of income tax effects cannot be reasonably estimated.

Measurement is complete	**Tax effects of the TCJA are reflected in the period of enactment.**
Measurement can be estimated	Provisional amounts must be recorded for items for which a reasonable estimate can be determined. Provisional amounts or subsequent adjustments to provisional amounts are to be included in continuing operations in the period amounts are determined
Measurement cannot be estimated	No amount is required to be recorded for items for which a reasonable estimate cannot be determined. Registrants would continue to apply ASC 740 based on the provisions of the tax laws in effect immediately prior to the enactment of the TCJA.

The accounting for some items may be completed earlier than others; as a result, all three scenarios will need to be considered. The measurement period ends when the information necessary for the entity to finalize its accounting has been obtained, prepared and analyzed, not to extend beyond one year.

DISCLOSURES:

Disclosures should include:

- Qualitative disclosures for which the accounting is incomplete
- Items reported as provisional amounts
- Existing current or deferred amounts for which measurement of the effect of the TCJA has not been completed
- Reason the initial accounting is incomplete
- Additional information required, prepared or analyzed to complete accounting measurement
- Nature and amount of measurement adjustment recognized during the reporting period
- Effect of measurement period adjustments on the effective tax rate
- When the accounting for the effect of the TCJA has been completed

SAB 118 additionally clarifies that re-measurement of a deferred tax asset to reflect a change in tax rate or tax laws is not an impairment under ASC 740, and disclosure under Item 2.06 of Form 8-K is therefore not required.

The Company has determined reasonable estimates of the effects of the TCJA, and recognized the estimates in its financial statements for the year ended Dec. 31, 2017, but notes that given expected changes to U.S. Treasury regulations, interpretations of the TCJA by the U.S. Treasury or IRS, interpretations of the application of ASC 740, and developing regulatory guidance and orders these estimates are subject to change.

INTERNAL CONTROL CONSIDERATIONS:

With the enactment of the TCJA, the Company assessed its control environment and identified required control activities specific to the calculation and implementation of the TCJA due to the broad reaching changes of the TCJA, the multiple departments impacted

(Tax, Accounting, Regulatory), the differing regulatory treatment across all the jurisdictions the Company operates in and the short period of time to review, interpret and implement the TCJA.

Due to the far reaching and complex nature of the TCJA, the Company developed a strategic plan which was implemented according to the following controls present in the Company's control environment:

Control #	Control Description
TAX CYCLE #3	The General Accountants prepare the monthly tax provision journal entry(s), which is reviewed and approved by the Tax Manager, as evidenced by electronic sign-off in PowerTax.
CORP ACCOUNTING CYCLE #9	All journal entries (manual, recurring, non-recurring) are reviewed and approved (initials) by a General Accountant, Sr. General Accountant, and / or the Manager Corporate Accounting. The Assistant Controller and / or Controller approves non-recurring journal entries if the earnings impact exceeds $0.01 earnings per share.
TAX CYCLE #5	Each quarter, the Tax Manager prepares the current tax account balance sheet reconciliations and any resulting adjusting journal entries. Balance sheet reconciliations are reviewed and approved by the Manager, SEC Reporting and the Controller within 30 days of quarter end. For the third and fourth quarters, the Tax Manager prepares the SFAS 109 balance sheet reconciliations and any adjusting journal entries. Balance sheet reconciliations are reviewed and approved by the Manager, SEC Reporting and the Controller within 30 days of quarter end.
TAX CYCLE #6	Each quarter, the Tax Manager prepares the Effective Tax Rate Reconciliation, which is reviewed and approved by the Manager, SEC Reporting and the Controller.
TAX CYCLE #8	The Tax Manager compiles the Tax Footnote. The Tax Footnote, and supporting documentation, is forwarded to the Controller for review and approval as evidenced by initials and date on the supporting documentation. The approved Tax Footnote and supporting documentation is provided to the Manager, SEC Reporting.

TAX CYCLE #9	Each quarter, the Tax Manager and Controller attest to the FIN 48 Checklist / Memorandum detailing tasks performed to: i) identify new transactions and tax positions, and ii) identify changes to existing tax positions as required by FIN 48.

After review the above mentioned internal controls the Company determined that it could rely on the current controls to implement the Tax, GAAP, and Regulatory effect of the TCJA.

Please see Appendix C for a detailed listing of the Company's Implementation activities.

ADDENDUM 1 [Q2 2018 UPDATE]:

Please see *Unitil Annual Effective Tax Rate in Interim Reporting Memo Q2* 2018 for documentation of management's considerations and procedures used to produce this update.

Net Operating Loss Carryforward Offset

During the second quarter of 2018 the Company forecasted Net Operating Loss Carryforward (NOLC) utilization. Forecasted amounts included expected changes due to the TCJA of 2017 and other expected business variables such as changes in accrued revenue, PNGTS refunds, and pension contributions. While the Company was forecasting NOLC utilization, it reviewed the TCJA revaluation and associated accounting of the NOLC at yearend 2017.

The Company considers various factors when performing the NOLC consolidated accounting. Three primary factors are: (1) regulated subsidiary "stand-alone" basis, (2) non-regulated subsidiary intercompany tax payments to parent, and (3) non-regulated parent contra-NOLC consolidated credit offset accounting.

(1) ***Regulated Subsidiary Stand-Alone Basis:*** Regulated accounting requires regulated subsidiaries that participate in a tax sharing agreement (combined group) to account for income taxes on a "stand-alone" basis. Income taxes are an integral component of base ratemaking with significant jurisdiction importance. Therefore, current year income tax and all other tax attributes (i.e. NOLCs and other tax credit carryforwards) must be accounted for on the regulated subsidiaries general ledgers without consideration of the other subsidiaries in the combined tax filing group (i.e. "stand-alone" basis). Regulated subsidiaries will always settle taxes payable with the parent. Taxes refundable will be settled with the parent unless the combined group has (or generates) an NOLC. If the combined group has an NOLC the regulated subsidiary will account for the NOLC (on a "stand-alone" basis) in its rate base calculation.

(2) ***Non-regulated Subsidiary Intercompany Tax Payments to Parent:*** Non-regulated subsidiaries that belong to a combined group with regulated subsidiaries have their tax liability settled by the parent of the combined group. Intercompany tax payments or refunds to the parent generally occur on an

Unitil

annual/quarter basis to enable the parent of the combined group to remit required estimated tax payments. Non-regulated subsidiaries always settle taxes payable/receivable with the parent combined filer. Additionally, all non-regulated tax attributes are accounted on the parent combined filer's general ledger.

(3) ***Non-regulated Parent Contra-NOLC Consolidated Credit Offset Accounting:*** In the event that the combined group has an NOLC, the parent company will shelter taxes payable of non-regulated subsidiaries and record a balancing credit (payable) to account for regulated NOLCs on a consolidated and "stand-along" basis.

> ***Example:*** *Combined group has a $15MM NOLC and regulated subsidiaries have a $20MM NOLC (stand-alone basis). Non-regulated Parent Contra-NOLC Consolidated Credit Offset will be recorded as follows:*

Regulated Subsidiary NOLC	*$20MM*
Parent Contra-NOLC Credit Offset	*($ 5MM)*
Combined Group NOLC	*$15MM*

The Parent Contra-NOLC Credit Offset is created by non-regulated subsidiary taxes payable which are temporarily sheltered by the parent of the combined group up to the amount of NOLC generated by regulated subsidiaries. Once the parent has sheltered non-regulated taxes payable against all available combined group NOLCs, the parent will begin remitting taxes to the required taxing authority.

Regulated subsidiaries will continue to account for income taxes and NOLCs on the "stand-alone" basis after the combined NOLC has been completely utilized and will include its "stand-alone" basis NOLC when calculating intercompany tax payments due to the parent combined filer. When the combined group no longer has an NOLC, the use of regulated subsidiary "stand-alone" basis NOLC will cause an equal amount of the Parent Contra-NOLC Credit Offset to be due to the respective taxing authority. Therefore, the Parent Contra-NOLC Credit Offset represents future taxes payable of the combined group.

The TCJA revaluation of the Company's NOLC was performed in two parts. First, the Company revalued regulated subsidiary NOLCs and reduced the TCJA Regulatory Liability to be flowed back to ratepayers. Second, the Company revalued the Parent Contra-NOLC Credit Offset so that the consolidated NOLC would equal the available combined group NOLC.

After the Parent Contra-NOLC Credit Offset was revalued, intercompany payments were generated by the regulated subsidiaries to transfer the revalued amount to the TCJA Regulatory Liability increasing the amount flowed back to ratepayers. The transfer was completed with the following journal entry:

DR. Parent ADIT – NOLC B/S
CR. Intercompany Payable to Subs B/S

DR. Intercompany Receivable from Parent B/S
CR. Subsidiary TCJA Regulatory Liability B/S

The Company evaluated this intercompany transfer with respect to the 2018 regulatory developments and determined that the Parent Contra-NOLC Credit Offset represents non-regulated taxes payable due by the consolidated group which are no longer payable. As such, they should not be considered by the regulated subsidiaries on a “stand-alone” basis and the Company subsequently transferred the revalued amount back to the parent through intercompany tax payments with the following entry:

DR. Subsidiary TCJA Regulatory Liability B/S
CR. Intercompany Payable to Parent B/S

DR. Intercompany Receivable from Subs B/S
CR. Parent ADIT – NOLC B/S

[Please refer to APPENDIX K: PARENT CONTRA-NOLC CREDIT OFFSET for the revaluation technique used by the Company on its regulated NOLC and Parent Contra-NOLC Credit Offset]

Net Operating Loss Carryforward Offset Amortization

The revalued Parent Contra-NOLC Credit Offset is a non-regulated liability which is no longer deemed payable. It represents excess taxes sheltered at the 34% federal rate which will be payable at the new 21% federal rate. As a result, the Company determined a method to write off the impaired liability. Consistent with the method utilized to write off non-rate base EDIT, the Company will amortize the Parent Contra-NOLC Credit Offset as the underlying liability reverses (combined group NOL). The Company's forecasted 2018 NOL Utilization Ratio is 37.15% which creates $1.5MM Parent Contra-NOLC Credit Offset Amortization [Please refer to APPENDIX L: UNITIL 2018 TAXABLE INCOME FORECAST; Please refer to APPENDIX M: 2018 NOL UTILIZATION RATIO].

CHARITABLE CONTRIBUTIONS CREDIT CARRYFORWARD

The Company revalued its charitable contributions carryforward at December 31, 2017 in the amount of $190,013. This amount was transferred to the regulated entities through intercompany tax payments at December 31, 2017 and subsequently transferred back to the parent's general ledger with the Parent Contra-NOLC Credit Offset. Consistent with the recognition of other excess tax revaluations, the Company will amortize additional tax expense as the underlying asset reverses. The Company does not expect to recognize any related amortization in 2018 due to the forecast of NOLCs at the end of 2018.

ADDENDUM 1 [Q2 2018 UPDATE]:

Please see *Unitil Annual Effective Tax Rate in Interim Reporting Memo Q2* 2018 for documentation of management's considerations and procedures used to produce this update.

Net Operating Loss Carryforward Offset

During the second quarter of 2018 the Company forecasted Net Operating Loss Carryforward (NOLC) utilization. Forecasted amounts included expected changes due to the TCJA of 2017 and other expected business variables such as changes in accrued revenue, PNGTS refunds, and pension contributions. While the Company was forecasting NOLC utilization, it reviewed the TCJA revaluation and associated accounting of the NOLC at yearend 2017.

The Company considers various factors when performing the NOLC consolidated accounting. Three primary factors are: (1) regulated subsidiary "stand-alone" basis, (2) non-regulated subsidiary intercompany tax payments to parent, and (3) non-regulated parent contra-NOLC consolidated credit offset accounting.

(1) ***Regulated Subsidiary Stand-Alone Basis:*** Regulated accounting requires regulated subsidiaries that participate in a tax sharing agreement (combined group) to account for income taxes on a "stand-alone" basis. Income taxes are an integral component of base ratemaking with significant jurisdiction importance. Therefore, current year income tax and all other tax attributes (i.e. NOLCs and other tax credit carryforwards) must be accounted for on the regulated subsidiaries general ledgers without consideration of the other subsidiaries in the combined tax filing group (i.e. "stand-alone" basis). Regulated subsidiaries will always settle taxes payable with the parent. Taxes refundable will be settled with the parent unless the combined group has (or generates) an NOLC. If the combined group has an NOLC the regulated subsidiary will account for the NOLC (on a "stand-alone" basis) in its rate base calculation.

(2) ***Non-regulated Subsidiary Intercompany Tax Payments to Parent:*** Non-regulated subsidiaries that belong to a combined group with regulated subsidiaries have their tax liability settled by the parent of the combined group. Intercompany tax payments or refunds to the parent generally occur on an

Unitil

annual/quarter basis to enable the parent of the combined group to remit required estimated tax payments. Non-regulated subsidiaries always settle taxes payable/receivable with the parent combined filer. Additionally, all non-regulated tax attributes are accounted on the parent combined filer's general ledger.

(3) ***Non-regulated Parent Contra-NOLC Consolidated Credit Offset Accounting:*** In the event that the combined group has an NOLC, the parent company will shelter taxes payable of non-regulated subsidiaries and record a balancing credit (payable) to account for regulated NOLCs on a consolidated and "stand-along" basis.

> ***Example:*** *Combined group has a $15MM NOLC and regulated subsidiaries have a $20MM NOLC (stand-alone basis). Non-regulated Parent Contra-NOLC Consolidated Credit Offset will be recorded as follows:*

Regulated Subsidiary NOLC	*$20MM*
Parent Contra-NOLC Credit Offset	*($ 5MM)*
Combined Group NOLC	*$15MM*

The Parent Contra-NOLC Credit Offset is created by non-regulated subsidiary taxes payable which are temporarily sheltered by the parent of the combined group up to the amount of NOLC generated by regulated subsidiaries. Once the parent has sheltered non-regulated taxes payable against all available combined group NOLCs, the parent will begin remitting taxes to the required taxing authority.

Regulated subsidiaries will continue to account for income taxes and NOLCs on the "stand-alone" basis after the combined NOLC has been completely utilized and will include its "stand-alone" basis NOLC when calculating intercompany tax payments due to the parent combined filer. When the combined group no longer has an NOLC, the use of regulated subsidiary "stand-alone" basis NOLC will cause an equal amount of the Parent Contra-NOLC Credit Offset to be due to the respective taxing authority. Therefore, the Parent Contra-NOLC Credit Offset represents future taxes payable of the combined group.

The TCJA revaluation of the Company's NOLC was performed in two parts. First, the Company revalued regulated subsidiary NOLCs and reduced the TCJA Regulatory Liability to be flowed back to ratepayers. Second, the Company revalued the Parent Contra-NOLC Credit Offset so that the consolidated NOLC would equal the available combined group NOLC.

After the Parent Contra-NOLC Credit Offset was revalued, intercompany payments were generated by the regulated subsidiaries to transfer the revalued amount to the TCJA Regulatory Liability increasing the amount flowed back to ratepayers. The transfer was completed with the following journal entry:

DR. Parent ADIT – NOLC B/S
CR. Intercompany Payable to Subs B/S

DR. Intercompany Receivable from Parent B/S
CR. Subsidiary TCJA Regulatory Liability B/S

The Company evaluated this intercompany transfer with respect to the 2018 regulatory developments and determined that the Parent Contra-NOLC Credit Offset represents non-regulated taxes payable due by the consolidated group which are no longer payable. As such, they should not be considered by the regulated subsidiaries on a "stand-alone" basis and the Company subsequently transferred the revalued amount back to the parent through intercompany tax payments with the following entry:

DR. Subsidiary TCJA Regulatory Liability B/S
CR. Intercompany Payable to Parent B/S

DR. Intercompany Receivable from Subs B/S
CR. Parent ADIT – NOLC B/S

[Please refer to APPENDIX K: PARENT CONTRA-NOLC CREDIT OFFSET for the revaluation technique used by the Company on its regulated NOLC and Parent Contra-NOLC Credit Offset]

Net Operating Loss Carryforward Offset Amortization

The revalued Parent Contra-NOLC Credit Offset is a non-regulated liability which is no longer deemed payable. It represents excess taxes sheltered at the 34% federal rate which will be payable at the new 21% federal rate. As a result, the Company determined a method to write off the impaired liability. Consistent with the method utilized to write off non-rate base EDIT, the Company will amortize the Parent Contra-NOLC Credit Offset as the underlying liability reverses (combined group NOL). The Company's forecasted 2018 NOL Utilization Ratio is 37.15% which creates $1.5MM Parent Contra-NOLC Credit Offset Amortization [Please refer to APPENDIX L: UNITIL 2018 TAXABLE INCOME FORECAST; Please refer to APPENDIX M: 2018 NOL UTILIZATION RATIO].

CHARITABLE CONTRIBUTIONS CREDIT CARRYFORWARD

The Company revalued its charitable contributions carryforward at December 31, 2017 in the amount of $190,013. This amount was transferred to the regulated entities through intercompany tax payments at December 31, 2017 and subsequently transferred back to the parent's general ledger with the Parent Contra-NOLC Credit Offset. Consistent with the recognition of other excess tax revaluations, the Company will amortize additional tax expense as the underlying asset reverses. The Company does not expect to recognize any related amortization in 2018 due to the forecast of NOLCs at the end of 2018.

Unitil Corporation
TCJA Implementation Memo
Appendix C - TCJA Implementation Plan

Planning and Analysis

Date	Focus	Description
		2017
11/9/2017	All	Grant Thornton Tax Webinar
12/9/2017	Regulatory & GAAP	Internal Discussion - Finance (Regulatory & External Outlook) Discussion of aplicable law changes.
12/14/2017	Regulatory	Power & Utilities Tax Reform Update
12/19/2017	Regulatory & Tax	Webinar - How will Tax Reform impact your PowerPlan System
12/29-12/31	GAAP	Prepared ASC 740 Reconciliations to calculate Tax Rate Change Revaluation
		2018
1/3/2018	Tax & GAAP	Dicussed tax changes including Bonus Depreciation for Q4 2017 with external tax advisors
1/3/2018	All	Internal Unitil Financial Mangement planning meeting RE: Tax Reform
1/9/2018	Regulatory & GAAP	Meeting with Regulatory, General Accounting, and Tax to discuss ADIT in rate mechanisms.
1/29/2018	Tax & GAAP	Discussion with External Tax Consultants RE: Executive Comp (Section 162m).

System Configuration

Date	Focus	Description
		2018
1/11/2018	Regulatory & Tax	Conference Call with PowerPlan: PowerTax ARAM Setup | Rate Changes
1/16/2018	Regulatory & Tax	Updated tax rates in PowerPlan PowerTax Module (ARAM)
01/17-01/26	Regulatory & Tax	Processed ARAM calculation in PowerTax
2/6/2018	Tax & GAAP	Updated tax rates in PowerPlan Provision Module
2/7/2018	Tax & GAAP	Processed Rate Change in PowerPlan Provision Module
2/7/2018	Tax & GAAP	Updated PowerPlan Provision Module for new tax code changes

Internal Controls

Date	Focus	Description
		2018
01/02-01/05	ICFR	Tax Manager reviewed Internal Controls Document (404 Business Cycle) and Assessed Current Control Environment - See Internal Control Discussion in TCJA Implementation Memo.
1/19/2018	ICFR	Tax Manager reveiwed tax provision, all tax balance sheet reconciliations, All tax rollforward schedules, tax footnotes, and ETR reconciliation with the Chief Accounting Officer, Assistant Controller, Accounting Manager, and Manager of SEC Reporting

Unitil Corporation
TCJA Implementation Memo
Appendix C - TCJA Implementation Plan

Accounting for Income Taxes - Events and Implementation Steps

Date	Focus	Description
		2017
12/22/2017	ALL	TCJA Signed into Law
		2018
1/2/2018	ALL	NH Office of Consumer Advocate filed Complaint with the NHPUC "Regarding Unjust and unreasonable Rates" due to the tax rate reduction of the TCJA.
1/3/2018	ALL	NHPUC opened IR 18-001 "Investiation to Determine Rate Effects of Federal and State Corporate Tax Reductinos" to examine the effect of the tax rate reduction of the TCJA.
1/5/2018	GAAP & TAX	Finalized Tax Depreciation with Bonus Depreciation stopping September 27th.
1/8/2018	GAAP	Prepared ASC 740 Recon's for non-regulated entities, calculated EDIT, and posted the adjustment to the Tax Provision.
1/9/2018	ALL	State Offices of Consumer Advocates filed joint petition at FERC regarding the Justness and Reasonableness of Jurisdictional Utility Rates due to the tax rate reduciton of the TCJA.
1/11/2018	ALL	ME PUC Opened an "Investigation on of the impats of the TCJA on Maine Natural Gas Corporations".
1/15-1/17	GAAP	Prepared ASC 740 Recon's using 2017 Tax Rate for regulated entities, calculated EDIT, Calculated Gross Up Entry, and Posted the adjustment to Regulatory Liability.
1/18/2018	Regulatory	The Company held an internal meeting to discuss upcoming technical conference with the MEPUC RE: Impacts of the TCJA and its currently filed base rate case proceeding.
1/18/2018	Regulatory	The Company had a technical telephonic conference with the ME PUC "Regarding Tax Legislation Impact on Rate Case" discussing Cost of Service Reductions for decreased tax rates.
1/18-1/19	GAAP	Prepared ASC 740 Recon's using 2018 Tax Rate to ensure the re-valuation entries were correct.
1/26/2018	Regulatory & GAAP	The Company filed its ARAM forecast for subsidiary Northern Maine Division with the ME PUC.
1/29/2018	GAAP & TAX	Rolled PowerPlan - Provision Module to 2018. Updated all provisional accrual items to reflect changes in the TCJA.
1/29/2018	GAAP	Calculated FIN 18 wth new TCJA rates.
1/30/2018	Regulatory	The Company had a techinical telephonic conference with the ME PUC regarding the ARAM forecast submitted by the Company for subsidiary Northern - Maine Division.
2/5/2018	Regulatory & GAAP	Analyzed EDIT for Rate Base vs Non-Rate Base Attributes.
2/2/2018	ALL	MA DPU issued DPU 17-181 opening an investigation "Into the Effect of the Reduction in Federal Income Tax Rates on the Rates Charged by Electric, Gas, and Water Companies."
2/12/2018	GAAP	Based on further regulatory developments, re-calculated FIN 18 tax rate including identified non-rate base EDIT.
2/28/2018	Regulatory	ME PUC Issued final order regarding Northern Maine's base rate case proceedings. The ME PUC accepted the Company's calculation to adjust the Cost of Service for the tax rate reduction and accepted the Company's ARAM forcast to defer recovering EDIT until the next base rate case.

Unitil Corporation
TCJA Implementation Memo
Appendix C - TCJA Implementation Plan

Accounting for Income Taxes - Events and Implementation Steps (Continued…)

Date	Focus	Description
3/16/2018	Regulatory	UES Rate filing submitted to the NH PUC to reflect the impact of the TCJA
4/10/2018	GAAP & Regulatory	Review all TCJA balance sheet entries with Controller. Freeze balances until 2017 tax return RTA and/or further regulatory orders.
4/10/2018	GAAP	Review all Q1 TCJA tax provision adjustments and adjust according to any updated assumptions based on TCJA IRS regulations (if proposed).
7/3/2018	GAAP & TAX	Review all Q2 TCJA tax provision adjustments and adjust according to any updated assumptions based on TCJA IRS regulations (if proposed).
09/15-9/30	GAAP	Perform 2017 tax return RTA.
10/3/2018	GAAP & TAX	Review all Q3 TCJA tax provision adjustments and adjust according to any updated assumptions based on TCJA IRS regulations (if proposed).
12/26-12/31	GAAP & TAX	Review all Q4 TCJA tax provision adjustments and adjust according to any updated assumptions based on TCJA IRS regulations (if proposed).

Accounting for Income Taxes - Events and Implementation Steps | <u>Q2 2018 Interim Reporting Update</u>

Date	Focus	Description
4/30/2017	REGULATORY	NUPUC issued its final order approving rates for UES regarding the effect of the TCJA including the amount of ADIT to flowback to rate payers, the delay of the ADIT flow back, and the reduction of base rates due to the change in the federal tax rate.
5/1/2018	REGULATORY	FGE Rate filing submitted to the MDPU to reflect the impact of the TCJA
5/2/2018	REGULATORY	NUPUC approved settlement agreement between NU-NH, NHPUC Staff, and the OCA regarding the effect of the TCJA including the amount of ADIT to flowback to rate payers, the delay of the ADIT flow back, and the reduction of base rates due to the change in the federal tax rate.
5/2/2018	REGULATORY	Granite filed an uncontested rate settlement with FERC requesting no change in existing rates which accounted for the effects of the TCJA.
5/17/2018	GAAP & TAX	The Company met with its Actuary and discussed various funding scenarios based on the Actuary's cmpleted valuation of the Company's Pension assets. Based on discussions, the Company decided to make an additional $12M contribution on 8/31/2018 for Plan year 2017.
5/21/2018	GAAP & TAX	The Company estimated the additional $12M Pension tax deduction would contribute to the NOL in its 2017 tax return and assessed the impact of this transaction on the amounts accrued in the Company's 2017 income tax provision and balance sheet. It was determined the Company's NOLC balance at December 31, 2017 would increase when the Company recognizes, in 2018, the "return-to-accrual" adjustmetn for filing its 20174 tax return.
5/23 - 6/01	GAAP & TAX	The Company performed further analyses to assess the impact of the additional $12M pension contribution on its ADIT liabilities and to determine if an adjustment to those ADIT liabilities is appropriate in 2018. The adjustment to the non-utility entities of the Company for their portion of the additional pensiontax deduction in 2017 results in a non-regulated tax benefit of $546K to their tax provision in 2018.
6/1 - 6/22	GAAP & TAX	Company analyzed the forecasted 2018 utilization of its NOLC due to the acceleration of pension deductions, changes in accrued revenue, and other changes in book/tax timing items.

Unitil Corporation
TCJA Implementation Memo
Appendix C - TCJA Implementation Plan

Accounting for Income Taxes - Events and Implementation Steps | Q2 2018 Interim Reporting Update

Date	Focus	Description
6/25/2018	GAAP & TAX	The Company concluded that the NOLC has reached its peak at the end of 2017 and the NOLC will be utilized starting 2018 and the Company will begin to recognize a pro rata portion of the consolidating Parent Contra-NOLC Liability as the consolidated NOLC is recognized.
6/27/2018	REGULATORY	FERC approved Granite's filing from May 2, 2018 and stated it complies with the FERC Notice of Proposed Rulemaking concerning the justness and reasonableness of reates in light of the corporate income tax reduction under the TCJA.
6/29/2018	REGULATORY	MDPU issued an order accepting FGE's proposal to decrease the annual revenue requirement for both gas and electric divisions to account for the effect of the TCJA. The MDPU will address the refund of excess accumulated deferred income taxes in phase two of its investigation.
7/12/2018	GAAP & TAX	The Company met with Grant Thorton to discuss its updated 2017 pension contribution and NOLC utlization forecast. The Company concluded based on a pro-rata utilization of the total NOLC asset and will recognize a tax benefit of $1.5M in 2018
7/16/2018	GAAP & TAX	The Company's Management met with Senior/Executive Management to approve the new projected ETR of 19.26% for the remaining interim periods in 2018.

Unitil Corporation Consolidated
FIN 18 Analysis

For the Period Ended December 31, 2018

APPENDIX G

		Actuals	Actuals	Budget	Budget	Budget	Budget	Budget	Budget	Budget	Budget	Budget	Budget
	UTL	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Pretax Book Income	42,567,677	8,820,781	5,509,090	6,176,868	3,481,190	596,183	(9,592)	1,333,257	416,617	911,613	1,319,033	5,615,257	8,397,380
Permanent Items					-			-		-	-		
Lobbying	196,603	14,693	20,830	16,108	16,108	16,108	16,108	16,108	16,108	16,108	16,108	16,108	16,108
Membership Dues	4,758	-	2,408	2,350	-	-	-	-	-	-	-	-	-
Penalties	33,739	3,500	7,739	1,100	1,500	1,000	6,000	1,500	1,000	6,600	1,100	1,600	1,100
Section 162(m)	600,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
State Regulatory Asset Amortization	191,740	15,978	15,978	15,978	15,978	15,978	15,978	15,978	15,978	15,978	15,978	15,978	15,978
Unallowable Meals	43,501	499	1,956	4,005	3,740	3,841	4,956	3,666	3,686	4,456	3,834	4,146	4,720
Total Permanent Items	**1,070,342**	**84,670**	**98,911**	**89,541**	**87,326**	**86,927**	**93,042**	**87,252**	**86,772**	**93,142**	**87,020**	**87,832**	**87,906**
ITC Amortization													
Unamortized ITC	-	-	-	-	-	-	-	-	-	-	-	-	-
Total ITC Amortization	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
State Taxable Base	**43,638,018**	**8,905,451**	**5,608,001**	**6,266,409**	**3,568,516**	**683,110**	**83,450**	**1,420,509**	**503,389**	**1,004,755**	**1,406,053**	**5,703,089**	**8,485,286**
State Tax Expense													
State Tax Expense	3,588,958	734,387	466,305	519,787	297,518	54,132	319	107,608	36,136	79,128	112,790	481,026	699,822
Total State Tax Expense	**3,588,958**	**734,387**	**466,305**	**519,787**	**297,518**	**54,132**	**319**	**107,608**	**36,136**	**79,128**	**112,790**	**481,026**	**699,822**
Federal Taxable Base	**40,049,060**	**8,171,064**	**5,141,697**	**5,746,622**	**3,270,998**	**628,978**	**83,131**	**1,312,901**	**467,253**	**925,627**	**1,293,263**	**5,222,063**	**7,785,464**
Federal Tax Expense													
Federal Tax Expense	8,410,303	1,715,923	1,079,756	1,206,791	686,910	132,085	17,457	275,709	98,123	194,382	271,585	1,096,633	1,634,947
Federal Tax Credits	(14,801)	(2,080)	(2,080)	(1,615)	(916)	(930)	(1,247)	(882)	(882)	(1,090)	(916)	(991)	(1,172)
Total Federal Tax Expense	**8,395,502**	**1,713,843**	**1,077,676**	**1,205,176**	**685,994**	**131,155**	**16,210**	**274,827**	**97,241**	**193,292**	**270,669**	**1,095,642**	**1,633,775**
Other Tax Items													
Excess ADIT	(1,688,435)	-	(375,000)	(550,000)	(59,041)	(5,000)	25,000	(36,000)	10,000	(20,000)	(42,000)	(255,000)	(381,394)
Charitable Contributions Carryforward Revalue	190,013	-	-	-	-	-	190,013	-	-	-	-	-	-
NOLC Offset Amortization	(1,470,383)	-	(326,571)	(478,971)	(51,416)	(4,354)	21,771	(31,351)	8,709	(17,417)	(36,576)	(222,068)	(332,139)
RTA - Pension Payments	(545,563)	-	(121,169)	(177,715)	(19,077)	(1,616)	8,078	(11,632)	3,231	(6,462)	(13,571)	(82,395)	(123,235)
RTA	1,514	-	-	-	-	-	-	-	-	1,514	-	-	-
FGE ITC AMORT	(41,923)	(3,494)	(3,494)	(3,494)	(3,494)	(3,494)	(3,494)	(3,494)	(3,494)	(3,494)	(3,494)	(3,494)	(3,494)
Regulatory Amortization	(216,765)	(21,107)	(20,027)	(17,563)	(17,563)	(17,563)	(17,563)	(17,563)	(17,563)	(17,563)	(17,563)	(17,563)	(17,563)
Total Other Tax Items	**(3,785,161)**	**(24,601)**	**(859,880)**	**(1,227,742)**	**(150,591)**	**(32,027)**	**223,806**	**(100,040)**	**883**	**(63,422)**	**(113,203)**	**(580,520)**	**(857,825)**
Net Income After Tax	**34,368,378**	**6,397,151**	**4,824,990**	**5,679,647**	**2,648,269**	**442,922**	**(249,927)**	**1,050,862**	**282,357**	**702,615**	**1,048,777**	**4,619,108**	**6,921,607**
2018 ETR	**19.26%**												
2018 YTD ETR			**21.69%**	**17.58%**	**18.50%**	**18.68%**	**19.66%**	**19.74%**	**19.94%**	**20.04%**	**20.06%**	**19.68%**	**19.26%**

APPENDIX K: PARENT CONTRA-NOLC CREDIT OFFSET

Step I - Consolidated NOLC | $20.1M Consolidated [$30.5M NOLC at Regulated Sub: $10.4M Payable at Corp]

	Consolidated	Ucorp	FGE	UES	NUNH	NUME	GSGT
NOLC @ 34%	20,119,577	(10,350,955)	2,695,091	1,228,316	6,527,475	16,760,120	3,259,530

	NOLC Available	Taxable Income	Remaining NOLC	Cash Paid
Regulated Subs	30,470,532	-	-	-
Ucorp NOLC Offset	(10,350,955)			-
Consolidated NOLC	20,119,577	-	-	-

1. Regulated subs have $30.4MM NOL to offset future taxable income
2. Ucorp has sheltered $10.3 Million of unregulated subs' taxable income with consolidated NOL

Step II(a) - Taxable Income results in $30.5M tax liability (before NOLC deduction) in current year taxed at 34%

	NOLC Available	Taxable Income	Remaining NOLC	Cash Paid
Regulated Subs	30,470,532	(30,470,532)	-	-
Ucorp NOLC Offset	(10,350,955)			10,350,955
Consolidated NOLC	20,119,577	(30,470,532)	-	10,350,955

1. Regulated subs utilize 100% of "stand alone" NOLC
2. Ucorp's $10.3M unregulated subs' sheltered tax liability becomes due

Step II(b) - Taxable Income results in $40.5M tax liability (before NOLC deduction) in current year taxed at 34%

	NOLC Available	Taxable Income	Remaining NOLC	Cash Paid
Regulated Subs	30,470,532	40,470,532	-	10,000,000
Ucorp NOLC Offset	(10,350,955)			10,350,955
Consolidated NOLC	20,119,577	40,470,532	-	20,350,955

1. Regulated subs utilize 100% of "stand alone" NOLC and owe an additional $10M in current taxes payable
2. Ucorp's $10.3M unregulated subs' sheltered tax liability becomes due

Step II(c) - Taxable Income results in $25.5M tax liability (before NOLC deduction) in current year taxed at 34%

	NOLC Available	Taxable Income	Remaining NOLC	Cash Paid
Regulated Subs	30,470,532	25,470,532	5,000,000	-
Ucorp NOLC Offset	(10,350,955)		(5,000,000)	5,350,955
Consolidated NOLC	20,119,577	25,470,532	-	5,350,955

1. Regulated subs utilize $25.5M of "stand alone" NOLC and carryforward $5M "stand alone" NOLC
2. The amount of Ucorp's unregulated subs' sheltered tax liability becomes due: equal to the amount of current year tax liability over consolidated NOLC

APPENDIX K: PARENT CONTRA-NOLC CREDIT OFFSET

Step III - Federal tax rate change from 34% to 21% | $12.4M Consolidated [$18.8M NOLC at Regulated Sub: $6.4M Payable at Corp]

	Consolidated	Ucorp	FGE	UES	NUNH	NUME	GSGT
NOLC @ 34%	20,119,577	(10,350,955)	2,695,091	1,228,316	6,527,475	16,760,120	3,259,530
NOLC @ 21%	12,426,798	(6,393,237)	1,664,615	758,666	4,031,676	10,351,839	2,013,239
NOLC Excess	7,692,779	(3,957,718)	1,030,476	469,650	2,495,799	6,408,281	1,246,291

	NOLC Available	Taxable Income	Remaining NOLC	Cash Paid
Regulated Subs	18,820,034	-	-	-
Ucorp NOLC Offset	(6,393,237)			-
Consolidated NOLC	12,426,798	-	-	-

NOLC Excess JE

		DR.	CR.	
1	ADIT NOLC (B/S)		11,650,498	NOLC Excess Regualted Subs
2	Reg Liability - TCJA ARAM FlowBack (B/S)	11,650,498		NOLC Excess Regualted Subs
3	ADIT NOLC (B/S)	3,957,718		NOLC Excess Unregualted Subs
4	Deferred Tax Provision (P&L)		3,957,718	NOLC Excess Unregualted Subs
	Control Total	**15,608,216**	**15,608,216**	

Net NOLC Reduction Line 1 (CR) + Line 3 (DR)	**(7,692,779)**
Net Regulatory Liability Line 2 (DR)	**11,650,498**
Net Deferred Tax Provision Line 4 (CR)	**(3,957,718)**

Step IV(a) - Taxable Income results in $18.8M tax liability (before NOLC deduction) in current year taxed at 21%

	NOLC Available	Taxable Income	Remaining NOLC	Cash Paid
Regulated Subs	18,820,034	(18,820,034)	-	-
Ucorp NOLC Offset	(6,393,237)			6,393,237
Consolidated NOLC	12,426,798	(18,820,034)	-	6,393,237

1. Regulated subs utilize 100% of "stand alone" NOLC
2. Ucorp's $6.4M unregulated subs' sheltered tax liability becomes due

Step IV(b) - Taxable Income results in $28.8M tax liability (before NOLC deduction) in current year taxed at 21%

	NOLC Available	Taxable Income	Remaining NOLC	Cash Paid
Regulated Subs	18,820,034	28,820,034	-	10,000,000
Ucorp NOLC Offset	(6,393,237)			6,393,237
Consolidated NOLC	12,426,798	28,820,034	-	16,393,237

1. Regulated subs utilize 100% of "stand alone" NOLC and owe an additional $10M in current taxes payable
2. Ucorp's $6.4M unregulated subs' sheltered tax liability becomes due

Step IV(c) - Taxable Income results in $13.8M tax liability (before NOLC deduction) in current year taxed at 21%

	NOLC Available	Taxable Income	Remaining NOLC	Cash Paid
Regulated Subs	18,820,034	13,820,034	5,000,000	-
Ucorp NOLC Offset	(6,393,237)		(5,000,000)	1,393,236
Consolidated NOLC	12,426,798	13,820,034	-	1,393,236

1. Regulated subs utilize $13.8M of "stand alone" NOLC and carryforward $5M "stand alone" NOLC
2. The amount of Ucorp's unregulated subs' sheltered tax liability becomes due: equal to the amount of current year tax liability over consolidated NOLC.

APPENDIX L: UNITIL 2018 TAXABLE INCOME FORECAST

	12/31/2018	12/31/2017	
	2018 Estimated YTD	2017 Actual YTD	2018-2017 Change YTD
Pretax Book Income	40,039,310	46,542,558	(6,503,248)
Permanent Items			
Amort of Organization Rules	-	-	-
Lobbying	193,087	190,350	
MAOP Testing	-	-	-
Membership Dues	5,198	5,198	-
Penalties	16,100	12,348	3,752
State Regulatory Asset Amortization	191,741	191,740	1
Officer Compensation SEC. 162(m)	600,000	-	600,000
Unallowable Meals	37,489	36,896	593
Total Permanent Items	**1,043,615**	**436,532**	**607,083**
Temporary Items			
Accrued Revenue	8,703,752	(4,196,611)	12,900,364
Bad Debt	763,166	399,393	363,773
Bad Debt Reg Asset	84,809	(33,659)	118,468
Debt Discount Expense	1,920	1,920	-
Deferred Rate Case	646,152	987,570	(341,418)
DER Investment Amortization	11,021	11,020	1
FAS 109 Amortization	-	-	-
Gas Refund	-	-	-
Insurance Claim Reserve	10,318	(118,436)	128,755
Indenture Costs	28,704	28,704	-
Integrity Management Program	(91,154)	(14,076)	(77,078)
Merger Costs	-	-	-
Legal Fees	-	-	-
Pension FAS 87	(4,140,216)	(11,784,986)	7,644,770
Pension FAS87 Reg Asset	(59,315)	(59,315)	-
PNGTS Refund	(2,258,386)	(4,507,047)	2,248,661
Prepaid Property Tax	286,800	(255,450)	542,250
R&D Deduction	-	(10,711,716)	10,711,716
Remediation	1,859,011	1,753,997	105,014
Restricted Stock	607,550	607,550	(0)
SERP	1,332,098	1,305,054	27,044
SFAS 106 OPEB	5,042,116	5,037,116	5,000
SFAS 106 OPEB Reg Asset	(332,637)	(332,637)	-
State Regulatory Asset Amortization	257,948	257,948	-
Storm Restoration	502,643	2,452,179	(1,949,536)
Transaction Costs	724,848	783,750	(58,902)
Transition Costs	694,379	748,606	(54,227)
Total Temporary Items	**17,940,438**	**(17,639,127)**	**35,579,565**
Temporary Plant			
Amort of Purchase Discount	(2,237,328)	(2,477,009)	239,681
Book Amort of Software	2,239,518	1,209,936	1,029,582
Book Depreciation	37,877,220	39,420,973	(1,543,753)
CIAC	418,376	61,807	356,569
CIAC Non-Refundable	3,769,616	4,462,389	(692,774)
Repairs Expense	(32,438,774)	(28,512,890)	(3,925,884)
Tax Depreciation	(38,488,010)	(52,855,914)	14,367,904
Total Temporary Plant	**(28,859,382)**	**(38,690,708)**	**9,831,326**
ITC Amortization			
Unamortized ITC	-	(1,113)	1,113
Total ITC Amortization	**-**	**(1,113)**	**1,113**
State Tax Expense	**(4,781,735)**	**(45,509)**	**(4,736,226)**
Federal Taxable Income	**25,382,247**	**(9,144,242)**	**34,526,488**

APPENDIX M: 2018 NOL UTILZATION RATIO

LN/COL	(a)	(b)
1	NOL Available	68,319,471
2	2018 Taxable Income (See APPENDIX L)	25,382,247
3	2018 NOL Utilization ratio (Line 2 / line 1)	37.15%
4	Parent Contra-NOLC Credit Offset Amortization (Line 5 * Line 3)	1,470,383
5	Parent Contra-NOLC Credit Offset (See APPENDIX K)	3,957,718
6	Remaining Parent Contra-NOLC Credit Offset (Line 5 - Line 4)	2,487,335

Date: October 17, 2018
To: Mark Collin, Chief Financial Officer; Laurence Brock, Chief Accounting Officer;
From: Jonathan Giegerich, Tax Manager
Re: Annual Effective Tax Rate in Interim Reporting Update – Q3

EXECUTIVE SUMMARY:

The Company filed its tax returns for the year ended December 31, 2017 with the Internal Revenue Service in September 2018 and generated additional federal net operating loss (NOL) carryforward assets principally due to current pension deductions, tax repair deductions, tax depreciation and research and development deductions. As of September 30, 2018, the Company had recorded cumulative federal and state NOL carryforward assets of $18.2 million to offset against taxes payable in future periods. If unused, the Company's NOL carryforward assets will begin to expire in 2029. In addition, at September 30, 2018, the Company had $3.4 million of cumulative alternative minimum tax credits, general business tax credit and other state tax credit carryforwards to offset future income taxes payable.

As a result of filing its 2017 tax returns and conducting a Return to Accrual (RTA) analysis with Grant Thornton, the Company's tax preparers during the third quarter, the Company re-evaluated the effective tax rate to be used in interim period reporting to reflect the 2017 RTA analysis and other current events and changes in the regulatory and tax environments. The purpose of this memo is to document management's process in analyzing the impact of these developments on the Company's 2018 Effective Tax Rate ("ETR") and to document management's findings and analysis as described below.

MANAGEMENT'S FINDINGS AND ANALYSIS:

During the second quarter of 2018 management updated the accounting estimate for the Annual Effective Tax Rate in Interim Reporting with the following steps:

1. **IDENTIFICATION OF KEY FACTORS:**

   a. The Company filed its 2017 federal and state tax returns in September 2018. The Company included in the filing the $12MM additional tax deduction for pension payments made on September 7, 2018 as discussed in the 2018 Q2 Update Memo. [Please see Q2 ANNUAL EFFECTIVE TAX RATE IN INTERIM REPORTING UPDATE memo for details]. Additionally, the Company included certain changes related to utility plant differences after the final tax repairs, tax depreciation, gain/loss, cost of removal, and salvage was reconciled in the PowerTax database. The Company also had other immaterial adjustments related to other book/tax timing differences.

   b. Management estimated the additional tax deductions over the 2017 year end provision estimate would impact rate base and non rate base EDIT and would affect the 2018 ETR. Management reviewed all Return to Accrual (RTA) adjustments per the 2017 tax return filing with the Company's tax specialists on September 26, 2018.

   c. Management updated its estimated 2018 taxable income based on 2018 actuals through September 2018 and estimated that the projected 2018 ETR would be 18% down 1.3% from the Company's Q2 analysis. [PLEASE SEE APPENDIX G, APPENDIX M, AND APPENDIX L OF THE TCJA MEMO FOR UPDATED ANALYSIS]

   d. **Regulatory Factors:** (1) On July 9, 2018 the MDPU announced Phase II of their TCJA investigation relative to the flow back of EDIT to ratepayers. (2). The Company has responded to various requests and the discovery period is still ongoing. Management concluded that no changes to previous regulatory EDIT estimates were needed due to continuing regulatory developments.

2. **MANAGEMENT'S COMMUNICATION OF REQUIRED NEW ESTIMATES:**

   a. **Communication of the need of a new estimate:** The previous conclusion about the Company's return to accrual adjustments effecting non rate base EDIT and the update to the 2018 taxable income prompted Management to analyze the forecasted 2018 ETR. Therefore, management met with the Company's tax specialists to discuss key factors previously identified and communicate criteria to develop a reasonable estimate of NOL utilization based on 2018 estimated taxable income.

b. **Accumulation of sufficient data:** Management and the Company's tax specialists met on October 1, 2018 and discussed historical year-over-year trends of book/tax timing differences, entity changes, and industry factors that affect the Company's 2018 estimate of book/tax timing differences and RTA adjustments which will be used in the new 2018 tax provision accounting estimate.

3. PREPARATION OF ACCOUNTING ESTIMATE BY QUALIFIED PERSONNEL:

a. The Company's tax specialists prepared a new forecast of 2018 NOLC utilization based on significant factors and historic assumptions from 2017 events to determine the tax return accrual items which occurred in 2017 and contributed to increasing the NOLC but would not recur in 2018 and, thus, the expected result is a significant utilization (decrease) to the NOLC is forecasted. See Appendix L: Unitil 2018 Taxable Income Forecast.

b. The Company's RTA analysis decreased the overall rate base EDIT (net of NOLC's) that will be flowed back to ratepayers by $65K. The Company's non-rate base EDIT increased by $4K due to immaterial other adjustments to non-rate base book/tax timing differences.

4. MANAGEMENT'S REVIEW OF ACCOUNTING ESTIMATE WITH SPECIALISTS:

a. The Company met with Grant Thornton, the Company's tax return preparer, to discuss its final tax return draft for approval and signature on September 20, 2018. The Company also discussed and confirmed the increase to NOLC in the 2017 period as well as to analyze the Company's updated 2018 Taxable Income Forecast to evaluate the utilization of NOLC in 2018 and to confirm the Company's estimated tax payments to federal and state jurisdictions for the 2018 tax period were adequate.

Unitil

5. **MANAGEMENT'S ANALYSIS OF THE 2018 TAX PROVISION ACCOUNTING ESTIMATE:**

   a. Based on the key factors, historical data, industry trends, and other assumptions developed by the Company's internal and external tax specialists; management concluded the NOLC has reached a peak at the end of 2017, and that the Company will utilize 47% of the NOLC in 2018; an increase from the 37% used in the second quarter analysis.

   b. Additionally Management determined that increases to non-rate base EDIT would not materially impact the forecasted 2018 ETR.

6. **MANAGEMENT'S SIGNOFF OF UPDATED ACCOUNTING ESTIMATE :**

   a. Based on the above analyses, discussions and input from its outside professionals; the Company updated its estimate of Unitil's expected ETR for 2018. Management determined it is appropriate to adjust its estimated ETR for 2018 to 18%, from the 19.26% it estimated at the end of the second quarter of 2018 based on filing the Company's 2017 tax returns in September, and the other factors listed above which arose in the third quarter of 2018. See Appendix G: Unitil Corporation Consolidated FIN 18 Analysis.

Unitil Corporation - Consolidating
12/31/2017
ADIT Tax Rate Revaluation - Rate Base v. Non Rate Base

APPENDIX B

	Consolidated	UES	NU_NH	NU_ME	FGE-G	FGE-E	GSGT
ADIT Rate Base Items							
Rate Base EDIT: Plant							
Utility Plant Differences	$ (47,476,178)	$ (16,553,252)	$ (6,664,456)	$ (9,041,438)	$ (7,696,326)	$ (6,317,717)	$ (1,202,988)
Rate Base EDIT: Non-Plant							
Contributions In Aid of Construction(CIAC)	$ 68,899	$ 68,899	$ -	$ -	$ -	$ -	$ -
SFAS 106 - PBOP	$ 3,243,230	$ 1,095,406	$ 353,227	$ 360,386	$ 660,451	$ 742,366	$ 31,394
FAS 87 - Pensions	$ (2,285,368)	$ (576,883)	$ (27,002)	$ (32,867)	$ (631,437)	$ (638,513)	$ (33,354)
Debt Discount Expense	$ (1,530)	$ (1,530)	$ -	$ -	$ -	$ -	$ -
Bad Debts	$ (16,432)	$ 33,522	$ 13,068	$ 25,939	$ (84,460)	$ (4,501)	$ -
Prepaid Property Tax	$ (309,201)	$ (204,989)	$ (93,408)	$ 39	$ -	$ -	$ (10,843)
Deferred Rate Case & Restructuring	$ (298,634)	$ (67,915)	$ (18,035)	$ (71,467)	$ -	$ (141,217)	$ -
DER INVESTMENT/IMP/MERGER	$ (15,531)	$ (15,531)	$ -	$ -	$ -	$ -	$ -
Indenture Costs	$ (45,614)	$ (45,614)	$ -	$ -	$ -	$ -	$ -
FAS109 Reg Asset	$ 58,273	$ 58,273	$ -	$ -	$ -	$ -	$ -
Insurance Settlement	$ 2,045	$ -	$ 743	$ 1,302	$ -	$ -	$ -
Total Rate Base EDIT: NON-PLANT	$ 400,137	$ 343,638	$ 228,593	$ 283,332	$ (55,446)	$ (41,865)	$ (12,803)
Total Rate Base EDIT	$ (47,076,041)	$ (16,209,614)	$ (6,435,863)	$ (8,758,106)	$ (7,751,772)	$ (6,359,582)	$ (1,215,791)
Non-Rate Base EDIT							
Accrued Revenue	$ (2,143,637)	$ (69,256)	$ (257,504)	$ (716,227)	$ (230,774)	$ (870,241)	$ -
Contributions In Aid of Construction(CIAC)	$ 26,817	$ -	$ -	$ -	$ 2,575	$ 24,242	$ -
Prepaid Property Tax	$ 35,058	$ -	$ -	$ -	$ 15,611	$ 19,447	$ -
Bad Debts	$ (5,505)	$ -	$ -	$ -	$ (2,354)	$ (3,151)	$ -
Storm Restoration	$ (883,981)	$ (770,318)	$ -	$ -	$ -	$ (113,663)	$ -
Transition Costs	$ (82,387)	$ -	$ (30,051)	$ (41,415)	$ -	$ -	$ (10,921)
Transaction Costs	$ 852,737	$ -	$ 350,620	$ 417,071	$ -	$ -	$ 85,046
Remediation	$ 520,547	$ -	$ 70,908	$ 270,218	$ 179,421	$ -	$ -
Rate Case	$ (432)	$ -	$ -	$ -	$ -	$ -	$ (432)
Insurance Settlement	$ (28,380)	$ -	$ -	$ -	$ (28,380)	$ -	$ -
IMP	$ (74,046)	$ -	$ -	$ -	$ -	$ -	$ (74,046)
Total NON Rate Base EDIT	$ (1,783,209)	$ (839,574)	$ 133,973	$ (70,353)	$ (63,901)	$ (943,366)	$ (353)
Grand Total EDIT	$ (48,859,250)	$ (17,049,188)	$ (6,301,890)	$ (8,828,459)	$ (7,815,673)	$ (7,302,948)	$ (1,216,144)

Unitil Corporation - Consolidated
APPENDIX B-1: Non-Ratebase EDIT Schedule
12/31/2018

APPENDIX B-1: Non-Rate Base EDITSchedule

	Total	2018	2019	2020	2021	2022	2023	2024
Accrued Revenue	$ (2,144,002)	$ (2,140,536)	$ (694)	$ (694)	$ (694)	$ (692)	$ (692)	$ -
Contributions In Aid of Construction(CIAC)	$ 26,817	$ 26,817						
Prepaid Property Tax	$ 35,058	$ 35,058						
Bad Debts	$ (5,505)	$ (5,505)						
Storm Restoration	$ (883,981)	$ (367,868)	$ (97,934)	$ (97,934)	$ (97,934)	$ (97,934)	$ (97,934)	$ (26,442)
Transition Costs	$ (82,387)	$ (82,387)						
Transaction Costs	$ 852,737	$ 852,737						
Remediation	$ 520,547	$ 93,857	$ 93,857	$ 93,857	$ 93,857	$ 93,857	$ 25,632	$ 25,632
Rate Case	$ (432)	$ (432)						
Insurance Settlement	$ (28,380)	$ (28,380)						
IMP	$ (74,046)	$ (74,046)						
Subtotal	$ (1,783,574)	$ (1,690,685)	$ (4,771)	$ (4,771)	$ (4,771)	$ (4,769)	$ (72,995)	$ (811)
Ucorp Charitable Contributions Carryforward	$ 190,013	$ 190,013						
Ucorp NOL Revaluation	$ (3,957,718)	$ (1,864,320)	$ (2,093,398)					
Total NON Rate Base EDIT Before 2017 RTA	$ (5,551,279)	$ (3,364,992)	$ (2,098,169)	$ (4,771)	$ (4,771)	$ (4,769)	$ (72,995)	$ (811)
RTA USC Pension Funding	$ (640,386)	$ (640,386)						
Total NON Rate Base EDIT	$ (6,191,665)	$ (4,005,378)	$ (2,098,169)	$ (4,771)	$ (4,771)	$ (4,769)	$ (72,995)	$ (811)

Unitil Corporation Consolidated
FIN 18 Analysis

For the Period Ended December 31, 2018

APPENDIX G

		Actuals	Actuals	Budget	Budget	Budget	Budget	Budget	Budget	Budget	Budget	Budget	Budget
	UTL	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Pretax Book Income	42,567,677	8,820,781	5,509,090	6,176,868	3,481,190	596,183	(9,592)	1,333,257	416,617	911,613	1,319,033	5,615,257	8,397,380
Permanent Items					-			-		-	-		
Lobbying	196,603	14,693	20,830	16,108	16,108	16,108	16,108	16,108	16,108	16,108	16,108	16,108	16,108
Membership Dues	4,758	-	2,408	2,350	-	-	-	-	-	-	-	-	-
Penalties	33,739	3,500	7,739	1,100	1,500	1,000	6,000	1,500	1,000	6,600	1,100	1,600	1,100
Section 162(m)	600,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
State Regulatory Asset Amortization	191,740	15,978	15,978	15,978	15,978	15,978	15,978	15,978	15,978	15,978	15,978	15,978	15,978
Unallowable Meals	43,501	499	1,956	4,005	3,740	3,841	4,956	3,666	3,686	4,456	3,834	4,146	4,720
Total Permanent Items	**1,070,342**	**84,670**	**98,911**	**89,541**	**87,326**	**86,927**	**93,042**	**87,252**	**86,772**	**93,142**	**87,020**	**87,832**	**87,906**
ITC Amortization													
Unamortized ITC	-	-	-	-	-	-	-	-	-	-	-	-	-
Total ITC Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-
State Taxable Base	**43,638,018**	**8,905,451**	**5,608,001**	**6,266,409**	**3,568,516**	**683,110**	**83,450**	**1,420,509**	**503,389**	**1,004,755**	**1,406,053**	**5,703,089**	**8,485,286**
State Tax Expense													
State Tax Expense	3,588,958	734,387	466,305	519,787	297,518	54,132	319	107,608	36,136	79,128	112,790	481,026	699,822
Total State Tax Expense	**3,588,958**	**734,387**	**466,305**	**519,787**	**297,518**	**54,132**	**319**	**107,608**	**36,136**	**79,128**	**112,790**	**481,026**	**699,822**
Federal Taxable Base	**40,049,060**	**8,171,064**	**5,141,697**	**5,746,622**	**3,270,998**	**628,978**	**83,131**	**1,312,901**	**467,253**	**925,627**	**1,293,263**	**5,222,063**	**7,785,464**
Federal Tax Expense													
Federal Tax Expense	8,410,303	1,715,923	1,079,756	1,206,791	686,910	132,085	17,457	275,709	98,123	194,382	271,585	1,096,633	1,634,947
Federal Tax Credits	(42,126)	-	-	-	-	-	-	-	(42,126)	-	-	-	-
Total Federal Tax Expense	**8,368,177**	**1,715,923**	**1,079,756**	**1,206,791**	**686,910**	**132,085**	**17,457**	**275,709**	**55,997**	**194,382**	**271,585**	**1,096,633**	**1,634,947**
Other Tax Items													
Excess ADIT	(1,690,685)	-	(375,000)	(550,000)	(59,041)	(5,000)	25,000	(36,000)	10,000	(20,000)	(42,000)	(255,000)	(383,644)
Charitable Contributions Carryforward Revalue	190,013	-	-	-	-	-	190,013	-	-	-	-	-	-
NOLC Offset Amortization	(1,864,321)	-	(326,571)	(478,971)	(51,416)	(4,354)	(78,229)	(156,351)	(141,291)	(367,417)	73,778	(111,714)	(221,785)
USC - Pension Payments	(640,386)	-									(213,462)	(213,462)	(213,462)
RTA	-	-	-	-	-	-	-	-	-	-	-	-	-
FGE ITC AMORT	(41,923)	(3,494)	(3,494)	(3,494)	(3,494)	(3,494)	(3,494)	(3,494)	(3,494)	(3,494)	(3,494)	(3,494)	(3,494)
Regulatory Amortization	(216,765)	(21,107)	(20,027)	(17,563)	(17,563)	(17,563)	(17,563)	(17,563)	(17,563)	(17,563)	(17,563)	(17,563)	(17,563)
Total Other Tax Items	**(4,264,067)**	**(24,601)**	**(725,091)**	**(1,050,027)**	**(131,514)**	**(30,411)**	**115,728**	**(213,407)**	**(152,348)**	**(408,474)**	**(202,741)**	**(601,233)**	**(839,948)**
Net Income After Tax	**34,874,608**	**6,395,071**	**4,688,121**	**5,500,318**	**2,628,276**	**440,377**	**(143,097)**	**1,163,347**	**476,832**	**1,046,577**	**1,137,398**	**4,638,830**	**6,902,558**
2018 ETR	**18.07%**												
2018 YTD ETR			**22.66%**	**19.13%**	**19.91%**	**20.06%**	**20.61%**	**20.21%**	**19.66%**	**18.51%**	**18.29%**	**18.14%**	**18.07%**

APPENDIX L: UNITIL 2018 TAXABLE INCOME FORECAST

	12/31/2018	12/31/2017	
	2018 Estimated YTD	2017 Actual YTD	2018-2017 Change YTD
Pretax Book Income	41,652,000	46,542,558	(4,890,558)
Permanent Items			
Amort of Organization Rules	-	-	-
Lobbying	193,087	190,350	
MAOP Testing	-	-	-
Membership Dues	5,198	5,198	-
Penalties	16,100	12,348	3,752
State Regulatory Asset Amortization	191,741	191,740	1
Officer Compensation SEC. 162(m)	450,000	-	450,000
Unallowable Meals	37,489	36,896	593
Total Permanent Items	**1,043,615**	**436,532**	**607,083**
Temporary Items			
Accrued Revenue	6,447,990	(4,189,345)	10,637,335
Bad Debt	663,166	409,392	253,774
Bad Debt Reg Asset	84,809	(33,659)	118,468
Debt Discount Expense	1,920	1,920	-
Deferred Rate Case	546,152	839,388	(293,236)
DER Investment Amortization	11,021	11,020	1
FAS 109 Amortization	-	512,231	(512,231)
Gas Refund	-	-	-
Insurance Claim Reserve	10,318	(131,510)	141,828
Indenture Costs	28,704	28,701	3
Integrity Management Program	(91,154)	(14,076)	(77,078)
Merger Costs	-	-	-
Legal Fees	-	-	-
Pension FAS 87	6,595,954	(11,988,936)	18,584,890
Pension FAS87 Reg Asset	(59,315)	(59,315)	-
PNGTS Refund	(2,258,386)	(4,507,047)	2,248,661
Prepaid Property Tax	171,800	(255,450)	427,250
R&D Deduction	(2,500,000)	(10,372,908)	7,872,908
Remediation	1,459,011	1,735,173	(276,162)
Restricted Stock	607,550	607,550	(0)
SERP	1,332,098	1,305,054	27,044
SFAS 106 OPEB	5,042,116	5,037,116	5,000
SFAS 106 OPEB Reg Asset	(332,637)	(332,637)	-
State Regulatory Asset Amortization	257,948	257,948	-
Storm Restoration	402,643	2,452,179	(2,049,536)
Transaction Costs	654,331	783,750	(129,418)
Transition Costs	686,222	748,607	(62,385)
Total Temporary Items	**19,762,262**	**(17,154,855)**	**36,917,117**
Temporary Plant			
Amort of Purchase Discount	(2,270,592)	(2,477,009)	206,417
Book Amort of Software	2,711,243	1,271,135	1,440,108
Book Depreciation	46,609,668	39,420,973	7,188,695
CIAC	418,376	61,807	356,569
CIAC Non-Refundable	3,269,616	4,462,389	(1,192,774)
Repairs Expense	(31,830,386)	(26,525,322)	(5,305,064)
Tax Depreciation	(40,082,531)	(63,460,225)	23,377,694
Total Temporary Plant	**(21,174,607)**	**(47,246,251)**	**26,071,645**
ITC Amortization			
Unamortized ITC	-	**(1,113)**	1,113
Total ITC Amortization			
State Tax Expense	**(4,102,662)**	**(869,768)**	**(3,232,894)**
Federal Taxable Income	**37,180,609**	**(18,292,898)**	**55,473,507**

APPENDIX M: 2018 NOL UTILIZATION RATIO

LN/COL	(a)	(b)
1	NOL Available	78,929,764
2	2018 Taxable Income (See APPENDIX L)	37,180,609
3	2018 NOL Utilization ratio (Line 2 / line 1)	47.11%
4	Parent Contra-NOLC Credit Offset Amortization (Line 5 * Line 3)	1,864,320
5	Parent Contra-NOLC Credit Offset (See APPENDIX K and/or B-1)	3,957,718
6	Remaining Parent Contra-NOLC Credit Offset (Line 5 - Line 4)	2,093,398

Date:	January 16, 2019
To:	Mark Collin, Chief Financial Officer; Laurence Brock, Chief Accounting Officer; Christine Vaughan, SVP Financial & Regulatory Services
From:	Jonathan Giegerich, Tax Manager
Re:	Annual Effective Tax Rate in Interim Reporting Update – Q4

EXECUTIVE SUMMARY:

During the fourth quarter, the Company completed its analysis of the annual effective tax rate ("ETR") used for period ending December 31, 2018 based on fiscal year 2018 actual results and changes in the regulatory and tax environments. The purpose of this memo is to document Management's process in analyzing the impact of these developments on the Company's 2018 ETR and to document management's findings and analysis as described below.

MANAGEMENT'S FINDINGS AND ANALYSIS:

During the fourth quarter of 2018 management finalized the accounting for the Annual Effective Tax Rate for period ending December 31, 2018 with the following steps:

1. **IDENTIFICATION OF KEY FACTORS:**

   a. **Regulatory Factors:** On November 15, 2018 the Federal Energy Regulatory Commission ("FERC") issued additional Notirce of Proposed Rulemaking ("NOPR") and a Policy Statement for accounting for Excess Deferred Income Tax ("EDIT") in formula and stated rates. Please see the Company's "2018 Q4 FERC Orders" memo for the Company's analysis of FERC's issued NOPRs.

On December 21, 2018 the MDPU issued Order DPU 18-15-E as a result of their Phase II investigation and ordered Fitchburg Gas and Electric Light Company ("FGE") to begin flow back of EDIT to ratepayers effective February 1, 2019. Included in the amount to be flowed back was EDIT previously identified by the Company as unprotected "Non Rate Base" EDIT. This EDIT was not ordered to be flowed back through distribution rates but to be reconciled through the flow through mechanisms which created the EDIT.

b. **Internal Revenue Service Factors:** In the fourth quarter of 2018 the IRS issued proposed Treasury Regulations for IRC §163(j) clarifying limitations imposed on interest expense deductions. These Treasury Regulations clarified the definition of exempt entities and provided a Di Minimis provision for combined tax filing groups.

c. Management finalized its 2018 provision for taxable income estimate based on 2018 general ledger actuals through December 2018 and changes in the Company's regulatory environment and calculated the 2018 ETR would be 20.25% an increase of 2.25% from the Company's Q3 analysis. [PLEASE SEE APPENDIX G, APPENDIX M, AND APPENDIX L OF THE TCJA MEMO FOR UPDATED ANALYSIS]

2. MANAGEMENT'S COMMUNICATION OF REQUIRED NEW ESTIMATES:

a. **Communication of the need of a new estimate:** The previous conclusion about the Company's treatment of non rate base EDIT and the update to the 2018 taxable income prompted Management to analyze the 2018 ETR. Therefore, management met with the Company's tax specialists to discuss key factors previously identified and communicate criteria to develop a reasonable estimate of NOL utilization based on 2018 estimated taxable income. [PLEASE SEE APPENDIX N OF THE TCJA MEMO FOR REGULATORY TREATMENT OF EDIT IN THE COMPANY'S REGULATORY JURISDICTIONS]

b. **Accumulation of sufficient data:** Management and the Company's tax specialists met on January 4th, 9th, and 10th of 2019 and discussed the final accounting results of book/tax timing differences and regulatory changes that affect the Company's 2018 year-end tax provision accounting estimate.

Unitil

c. **Analysis of compiled regulatory data:** Management, the Company's tax specialist, and the Company's regulatory specialists met on January 2, 2018 to discuss implementation of DPU 18-15-E relative to base distribution rates and distribution flow through mechanisms. Management identified all previously identified unprotected "Non Rate Base" EDIT generated from distribution flow through mechanisms. The Company will follow the DPU's Order 18-15-E in future regulatory reconciliation filings to reconcile unprotected "Non Rate Base" EDIT which was never collected from ratepayers. Please see memo "2018 Q4 DPU Orders" for the Company's analysis of the order.

d. **Analysis of compiled IRS data:** The Company's tax specialists reviewed Edison Electric Institute ("EEI") guidance issued at the end of November 2018 with the Company's tax advisor, Grant Thornton (See Attached EEI Communication). Additionally, the Company's tax specialists attended an EEI Member webcast on December 18, 2018 which discussed the proposed Treasury Regulations on Business Interest Limitations (See attached slides). The Company determined that non regulated entities in a combined tax filing group which exist to support the operations of regulated entities are defined as exempt entities under the proposed Treasury Regulations. With the exception of Usource Inc. (Usource LLC is considered under Usource Inc. for federal tax purposes as it is deemed a disregarded entity by the IRS), the Company identified all other non-regulated entities in its combined group as supporting the operations of its regulated entities and are therefore classified as exempt entities under IRC §163(j). Additionally, when applying the 10% Di Minimis provision, Usource Inc.'s asset tax basis is covered by the safe harbor provision and no adjustment is necessary for IRS §163(j).

3. PREPARATION OF ACCOUNTING ESTIMATE BY QUALIFIED PERSONNEL:

a. The Company's tax specialists prepared a year-end calculation of the 2018 NOLC utilization based on the Company's year-end pre-tax book accounting and determined the result is an utilization (decrease) of 46.90% to the NOLC. See Appendix L: Unitil 2018 Taxable Income Forecast and Appendix M: 2018 NOL Utilization Ratio.

b. Based on the DPU Order 18-15-E, the Company froze the unprotected "Non Rate Base" Edit for FGE as of 12/31/2017 and will recognize the benefit when the Company reconciles these amounts through future regulatory filings.

4. MANAGEMENT'S REVIEW OF ACCOUNTING ESTIMATE WITH SPECIALISTS:

a. The Company met with Grant Thornton, the Company's tax return preparer, to discuss its analysis of the proposed Treasury Regulations of IRC §163(j) on January 9, 2019. The Company also discussed and confirmed the use of the NOLC in the 2018 period and confirmed that the Company's estimated tax payments to federal and state jurisdictions for the 2018 tax period were adequate.

5. MANAGEMENT'S ANALYSIS OF THE 2018 TAX PROVISION ACCOUNTING ESTIMATE:

a. Based on the key factors, regulatory data, IRS data, and other assumptions developed by the Company's internal and external tax specialists; management concluded that the Company will utilize 46.90% of the NOLC in 2018.

b. Additionally, Management determined that adjusting FGE non-rate base EDIT will impact the 2018 ETR and increase it by approximately 2%.

6. MANAGEMENT'S SIGNOFF OF UPDATED ACCOUNTING ESTIMATE :

a. Based on the above analyses, discussions and input from its outside professionals; the Company finalized the ETR for 2018. Management determined it is appropriate to increase its estimated ETR for 2018 to 20.28%, from the 18.00% it estimated at the end of the third quarter of 2018 based on the IRS proposed Treasury Regulations for IRC §163(j), and the other regulatory factors listed above which arose in the fourth quarter of 2018. See Appendix G: Unitil Corporation Consolidated FIN 18 Analyses.

TCJA Q4 Memo Attachments

From: Tom Kuhn [mailto:tkuhn@eei.org]
Sent: Tuesday, November 27, 2018 10:15 PM
To: Unitil
Subject: Follow Up - Treasury's Proposed Regulations for the Business Interest Limitation

As you know, the Department of Treasury yesterday released the proposed regulations for the limitation on business interest. EEI's technical tax teams have been breaking down the proposed regulations, focusing on the key issues that were a part of our May 25th letter (attached) to the Treasury and the Internal Revenue Service. Based on the initial analysis, the proposed regulations contain a number of provisions important to our industry.

Proposed Regulations on the Business Interest Limitation - Sec. 163(j) of the Tax Cuts & Jobs Act:

- While it will take some time to understand more fully the implications to the industry, our initial view of the proposed regulations is positive because Treasury favorably addressed several important requests made in our industry letter.

- Most important, Treasury adopted the position that our exclusion from the interest limitation is determined at the consolidated group level. For purposes of this allocation between excluded regulated assets and non-regulated assets, Treasury proposed the use of the alternative depreciation system ("ADS") to determine asset basis, which was one of the methods of allocation proposed by the industry.

- Treasury strongly supported EEI's position regarding allocation on the basis that funds are fungible within a group. This notion is repeated several times within the proposed regulation.

- In response to our concern over the complexity of making allocations between excepted regulated businesses and non-excepted businesses, Treasury did include de minimis rules at EEI's request, proposing a mandatory application of a 10 percent de minimis standard. In our May letter, we suggested that these rules be elective and that 20 percent or less be considered de minimis. Thus, any group with 90 percent or more of its assets in its regulated utility business will be treated as a regulated utility taxpayer eligible for the full interest deduction.

- The proposed regulations did address the rules surrounding partnerships. They provide "look-through" rules to determine whether a partnership interest is allocable to an excepted or non-excepted business based on the nature of the partnership's business. While this rule and the general partnership rules in the proposed regulations require further study, it appears to be consistent with the industry's proposal in our May letter.

- There are some early concerns regarding the computation of adjusted taxable income (ATI), which is used as a basis for determining the limitation on deductible interest. As defined, ATI is taxable income with a number of adjustments, including the add back of depreciation. In the proposed regulations, Treasury has taken the position that depreciation capitalized to inventory (including electricity) and recovered through cost of goods sold is not depreciation that is added back to taxable income in computing ATI. This may substantially reduce the amount of the potential interest deduction for non-excepted (unregulated) businesses. This is another item that will require further analysis and one that will impact several industries, not just ours.

- Treasury has provided a 60-day comment period on the proposed regulations and has scheduled a public hearing on them for February 25, 2019. EEI will consider filing comments and appearing at the public hearing as it reviews their implications to the industry.

Again, from a high level, we believe the proposed regulations are positive for the industry. EEI's Interest Deductibility subgroup, which consists of member company CFOs, tax professionals, and Washington Representatives, will continue to analyze the proposed regulations and will begin to work through potential impacts the regulations may have on the industry.

Please remember that what was released is a proposed regulation. If issues arise or additional clarifications are needed, we do have time for further discussions with Treasury and IRS officials before they finalize the rules. We will continue to keep you updated.

I want to thank you and your Finance/Tax teams for all the input they provided throughout the year on this critical issue. As always, please let me know if you have any questions or ask your staff to contact Eric Grey (egrey@eei.org; 202-508-5471).

Cc: Washington Reps

- Treasury____IRS_Letter___Public_Utilities_Industry_Comments_on_163j_ 168k___05_25_18___FINAL.pdf
-
- **From:** Tom Kuhn [mailto:tkuhn@eei.org]
  Sent: Monday, November 26, 2018 5:15 PM
  To: Unitil
  Subject: Treasury Releases Proposed Regulations for the Business Interest Limitation
-
- The Department of Treasury and the Internal Revenue Service (IRS) this afternoon released the proposed regulations for the limitation on business interest – Section 163(j) of the Tax Cuts & Jobs Act (TCJA). This is the regulation that contains our industry's exemption from the interest limitation and addresses the issue of holding company debt.
-
- The proposed regulation (https://www.irs.gov/pub/irs-drop/REG-106089-18-NPRM.pdf) is 439 pages and is very complex. In addition, it has been split into two separate parts, with the rules regarding partnerships coming separately in early December. We are expecting the proposed regulation to be published in the Federal Register soon, which then will start the 60-day period to comment.

- EEI's Interest Deductibility subgroup, which consists of member company CFOs, tax professionals, and Washington Representatives, has begun to analyze the proposed regulation and will develop a high-level summary that we will send you. After that summary is complete, the subgroup then will do an even deeper analysis and begin working through potential impacts the regulations may have on the industry.
- Please remember that what was released today is a proposed regulation. If issues arise or additional clarifications are needed, we do have time to have further discussions with Treasury and IRS officials before they finalize the rule. We will continue to keep you updated.
- As always, please let me know if you have any questions or ask your staff to contact Eric Grey (egrey@eei.org; 202-508-5471).
- Cc: Washington Reps

UNITIL TCJA Q4 MEMO ATTACHMENTS

Edison Electric
INSTITUTE

Treasury's Proposed Regulations for the Business Interest Limitation - Sec.163ij)ofthelRC

Mark Agnew, Edison Electric Institute
Gaylord Gagnon, Arizona Public Service
Eric Grey, Edison Electric Institute
Alex Zakupowsky, Miller & Chevalier

December 18, 2018

Key Issues Addressed in the Reg's

Requested by EEi/industry	Proposed by Treasury
Industry exclusion determined at consolidated group	
Principle that debt is "fungible"	
Asset-based allocation methodology	
MACRS or ADS	
De Minimis threshold for "regulated % calculation"	
Partnership - excepted vs. non-excepted treatment applies	

EEi Subgroups Working on Sec 163{j)

- Interest Deductibility Subgroup (24 co's)
  - CFOs, Tax Leaders, Washington Reps
  - Builds off the Tax Reform Subcommittee
    - Primary group during the legislative effort
- Tax Analysis & Research Subcommittee (TARS) - steering group
- Taxation Committee - all EEi Members

EEi

EEi 163(j} Subgroup Process

- In reaction to the proposed regulations (439 pages), EEi's Interest Deductibility Subgroup & TARS developed a new issues list and related issue groups
- Five Issue Groups have been established
  - Trade or Business, Major Substantive Policy Issues, Definitions/Scope, Look Through, Administrative Issues
- Members drawn from Interest Deductibility Subgroup
- Group leads drawn from TARS
- Anticipated Outcome - Findings & Recommendations for EEi Comments

Interest Allocation 101

- Identify Assets as "Excepted" and "Non-Excepted"
  - Excepted or not excepted from the limitation - excepted a good thing
- More than 90% Excepted? → De Minimis Rule Applies → 100% Interest Deduction
- Less than 90%? Excepted? → Partial Interest Deduction
- Determination of the Partial Deduction
  - "Trade or Business" allocation of interest based on "Alternative Taxable Income" (ATI)
  - Deduct excepted + non-excepted interest up to 30% of ATI

EEi

Trade or Business

- Identified Issues for Review:
  - What is a Trade or Business for the Calculations?
    - Entire group? OR individual members of the consolidated group?
    - Relevant as to *where* the split between Excepted (interest deductible) and Non-Excepted (interest non-deductible) is determined
  - Regulated versus Non-Regulated Sales
    - Facility in cost of service – excepted?
  - De Minimis Rule
    - Not elective. Should it be?
  - Allocation of Assets is Based on kWh Production
    - Should it be? (difficult to administer)

Substantive Policy Issues

- Identified Issues for Review
  - Depreciation and the 30% ATI Limitation
    - Not "added back" to the limitation in the Proposed Regulations
    - Should it be added back to increase the limitation?
    - Higher the limitation, the more interest that is deductible
  - "Tracing"
    - Not allowed by the Proposed Regulations

Definitions/Scope

- Identified Issues for Review
  - Is "Interest" Properly Defined?
  - Depreciation System
    - ADS provided, but do we want an option for MACRS?
  - Bonus Depreciation for Non-excepted When the De Minimis Rule Applies?

Look Through & Administrative

- Look Through Identified Issues for Review
  - Does the "Look Through" to Assets in a Partnership work?
    - Adequate allocation of partner debt to "excepted"?
  - Does the Deemed Asset Sale Rule work?
- Administrative
  - Customer impacts
  - Need for Quarterly Computations

Timeline – Interest Deductibility

Date	Event
Dec '17	TCJA includes exception for utility industry
Mar '18	EEi meets with Treasury
May '18	EEi submits Treasury Comment Letter
Nov '18	Treasury Releases Proposed Regulations
Early Jan '19	Potential meeting with Treasury
Feb??, '19	Comments due to Treasury
Feb 25, '19	Treasury's Public Hearing
	Potential for a final regulation in 2019

EEi

Edison Electric INSTITUTE

Questions?

APPENDIX G

Unitil Consolidated
ETR Forecast
FIN 18 Calculation

	2018
PTBI	41,433,615
PERMS	782,375
ADJ PTBI	42,215,990
Statutory Rate	27.32%
Tax Expense	11,533,408
Other Tax Items:	
Excess ADIT	(532,730)
Charitable Contributions Carryfoward	190,013
NOLC Offset Amortization	(1,856,026)
RTA USC Pension Payments	(631,331)
RTA - Other	1,514
R&D Credit - NH	(42,126)
FGE ITC AMORT	(41,923)
Regulatory Amortization	(216,765)
Total Other Tax Items	(3,129,374)
Total Tax Expense	8,404,035
Net Income	33,029,580
ETR	20.28%

APPENDIX L: UNITIL 2018 TAXABLE INCOME FORECAST

	12/31/2018	12/31/2017	
	2018 Actual YTD	2017 Actual YTD	2018-2017 Change YTD
Pretax Book Income	41,433,615	46,542,558	(5,108,943)
Permanent Items			
Amort of Organization Rules	-	-	-
Lobbying	197,467	190,350	
MAOP Testing	-	-	-
Membership Dues	2,558	5,198	(2,640)
Penalties	54,338	12,348	41,990
State Regulatory Asset Amortization	191,741	191,740	1
Officer Compensation SEC. 162(m)	300,000	-	300,000
Unallowable Meals	36,271	36,896	(625)
Total Permanent Items	**782,375**	**436,532**	**345,843**
Temporary Items			
Accrued Revenue	7,833,084	(4,189,345)	12,022,429
Bad Debt	(309,978)	409,392	(719,370)
Bad Debt Reg Asset	123,428	(33,659)	157,087
Debt Discount Expense	1,920	1,920	-
Deferred Rate Case	705,145	839,388	(134,243)
DER Investment Amortization	11,020	11,020	(0)
FAS 109 Amortization	1,024,462	512,231	512,231
Insurance Claim Reserve	226,952	(131,510)	358,462
Indenture Costs	28,704	28,701	3
Integrity Management Program	8,450	(14,076)	22,527
Pension FAS 87	7,595,954	(11,988,936)	19,584,890
Pension FAS87 Reg Asset	(142,592)	(59,315)	(83,277)
PNGTS Refund	(2,258,386)	(4,507,047)	2,248,661
Prepaid Property Tax	23,116	(255,450)	278,566
R&D Deduction	-	(10,372,908)	10,372,908
Remediation	1,418,435	1,735,173	(316,738)
Restricted Stock	658,809	607,550	51,259
SERP	1,128,458	1,305,054	(176,596)
SFAS 106 OPEB	3,393,770	5,037,116	(1,643,346)
SFAS 106 OPEB Reg Asset	48,906	(332,637)	381,543
State Regulatory Asset Amortization	(109,812)	257,948	(367,760)
Storm Restoration	999,353	2,452,179	(1,452,826)
TCJA REV REQ	568,573	-	568,573
Transaction Costs	718,438	783,750	(65,312)
Transition Costs	686,452	748,607	(62,155)
Total Temporary Items	**24,382,660**	**(17,154,855)**	**41,537,515**
Temporary Plant			
Amort of Purchase Discount	(2,270,592)	(2,477,009)	206,417
Book Amort of Software	2,523,604	1,271,135	1,252,469
Book Depreciation	42,232,161	39,420,973	2,811,187
CIAC	861,491	61,807	799,684
CIAC Non-Refundable	2,443,770	4,462,389	(2,018,619)
Repairs Expense	(22,877,045)	(26,525,322)	3,648,277
Tax Depreciation	(50,451,988)	(63,460,225)	13,008,237
Total Temporary Plant	**(27,538,599)**	**(47,246,252)**	**19,707,653**
ITC Amortization			
Unamortized ITC	-	**(1,113)**	1,113
Total ITC Amortization			
State Tax Expense	**(2,044,857)**	**(869,768)**	**(1,175,089)**
Federal Taxable Income	**37,015,194**	**(18,292,898)**	**55,308,092**

APPENDIX M: 2018 NOL UTILIZATION RATIO

LN/COL	(a)	(b)
1	NOL Available	78,929,764
2	2018 Taxable Income (See APPENDIX L)	37,015,194
3	2018 NOL Utilization ratio (Line 2 / line 1)	46.90%
4	Parent Contra-NOLC Credit Offset Amortization (Line 5 * Line 3)	1,856,026
5	Parent Contra-NOLC Credit Offset (See APPENDIX K)	3,957,718
6	Remaining Parent Contra-NOLC Credit Offset (Line 5 - Line 4)	2,101,692

APPENDIX N: UNITIL TCJA REGULATORY MATRIX

	UES		FGE		NUNH		NUME		GSGT	
	PROTECTED	UNPROTECTED	PROTECTED	UNPROTECTED	PROTECTED	UNPROTECTED	PROTECTED	UNPROTECTED	PROTECTED	UNPROTECTED
TREATMENT PRE-RATE CASE APPROVAL	ALL DTA'S AND DTL'S REVALUED ON DECEMBER 31, 2017 AT LOWER RATE WITH OFFSET TO REGULATORY LIABILITY X0-X0-00-00-254-05-01. UNPROTECTED NON RATE BASE EDIT RECORDED IN 15-30-00-00-282-01-30		ALL DTA'S AND DTL'S REVALUED ON DECEMBER 31, 2017 AT LOWER RATE WITH OFFSET TO REGULATORY LIABILITY X0-X0-00-00-254-05-01. UNPROTECTED NON RATE BASE EDIT RECORDED IN 15-30-00-00-282-01-30		ALL DTA'S AND DTL'S REVALUED ON DECEMBER 31, 2017 AT LOWER RATE WITH OFFSET TO REGULATORY LIABILITY X0-X0-00-00-254-05-01. UNPROTECTED NON RATE BASE EDIT RECORDED IN 15-30-00-00-282-01-30		ALL DTA'S AND DTL'S REVALUED ON DECEMBER 31, 2017 AT LOWER RATE WITH OFFSET TO REGULATORY LIABILITY X0-X0-00-00-254-05-01. UNPROTECTED NON RATE BASE EDIT RECORDED IN 15-30-00-00-282-01-30		ALL DTA'S AND DTL'S REVALUED ON DECEMBER 31, 2017 AT LOWER RATE WITH OFFSET TO REGULATORY LIABILITY X0-X0-00-00-254-05-01. UNPROTECTED NON RATE BASE EDIT RECORDED IN 15-30-00-00-282-01-30	
COMMISSION APPROVAL DATE	4/30/2018		6/29/2018 & 12/21/2018		5/2/2018		2/28/2018		6/27/2018	
APPROVED AMORTIZATINO METHOD/LIFE	ARAM - APPLIED FOR	ARAM - APPLIED FOR	ARAM - APPROVED	ARAM - APPROVED	ARAM - APPLIED FOR	ARAM - APPLIED FOR	ARAM - APPLIED FOR	ARAM - APPLIED FOR	ARAM - APPLIED FOR	ARAM - APPLIED FOR
REVERSAL OF OVERCOLLECTION PRIOR TO RATE DECREASE	DEFERAL FOR PERIOD JAN 1 - APRIL 30 IS INCORPORATED IN BASE RATES FROM STEP FILING		DEFERAL FOR PERIOD JAN 1 - JUNE 30 IS AMORTIZED OVER 12 MONTHS		DEFERAL FOR PERIOD JAN 1 - APRIL 30 AMORTIZED OVER 12 MONTHS IN RECOUPMENT		NO REVERSAL - COMPANY KEEPS OVERCOLLECTION		NO REVERSAL - COMPANY KEEPS OVERCOLLECTION	
JE'S FOR REVERSAL OF DEFERRAL ACCUMULATED PRIOR TO RATE	NO JE		DR. REGULATORY LIABILITY CR. ACCRUED REVENUE		DR. REGULATORY LIABILTIY CR. RECOUPMENT REVENUE		NO JE		NO JE	

Date: November 19, 2018
To: File
From: Jonathan Giegerich, Tax Manager
Re: 2018 Q4 FERC Orders:

EXECUTIVE SUMMARY:

The Federal Energy Regulatory Commission ("FERC") issued a news release on November 15, 2018. Included in the news release was a Notice of Proposed Rulemaking ("NOPR") (RM19-5-000) and a Policy Statement (PL19-2-000) to address the Tax Cuts and Jobs Act's ("TCJA") effects on the Accumulated Deferred Income Taxes ("ADIT") on transmission rates. More specifically in the Policy Statement and the NOPRs, the FERC defines excess ADIT to be flowed back to rate payers as *"…a portion of an ADIT liability that was collected from customer will no longer be due from public utilities, natural gas pipelines and oil pipelines to the IRS and is considered excess ADIT" (PL19-2-000 Page 2, Paragraph 3).*

Under the proposed rules all public utilities with transmission formula rates would:

- Include mechanisms to deduct any excess ADIT from or add any deficient ADIT to their rate bases;
- Include mechanisms in those rates that would raise or lower their income tax allowances by any amortized excess or deficient ADIT; and
- Incorporate a new permanent worksheet into their rates that will annually track information related to excess or deficient ADIT.

Under the proposed rules, all public utilities with transmission stated rates would determine the amount of excess and deferred income tax caused by the reduced federal corporate income tax rate, and return or recover this amount to or from customers.

MANAGEMENT'S FINDINGS AND ANALYSIS:

NOPR-RM19-5-000: The FERC addressed three topics in the NOPR: (1) preservation of rate base neutrality through the removal of excess ADIT from or addition of deficient ADIT to rate base; and (2) the return of excess ADIT to or recovery of deficient ADIT from ratepayers, and (3) support for excess and deficient ADIT calculation and amortization. Additionally these three topics were discussed relative to two rate categories—formula rates and stated rates. Unitil (the "Company") has two subsidiaries subject to FERC regulation Fitchburg Gas and Electric Light Company ("FGE") and Granite State Gas Transmission Company ("GSGT") with each being subject to one of the two rate categories formula and stated rates, respectively.

1. **PRESERVATION OF RATE BASE NEUTRALITY THROUGH THE REMOVAL OF EXCESS ADIT FROM OR ADDITION OF DEFICIENT ADIT TO RATE BASE.**

   When tax rates change companies are required to revalue their ADIT in the enactment period for the new effective tax rate. Consequently the ADIT reduction to rate base will either increase (tax rate increase) which decreases rate base or the ADIT reduction to rate base will decrease (tax rate decrease) which increases rate base. Public utility companies record ADIT revaluations in Account 182.3 (Other Regulatory Assets) and Account 254 (Other Regulatory Liabilities) to be collected or flowed back in rates. These unamortized balances must continue to be considered in the rate base calculation. Therefore, to achieve rate base neutrality the corresponding (revalued) amounts recorded in Accounts 254 and 182.3 should be deducted from or added to rate base just as the ADIT balances which were appropriately deducted from or added to rate base (prior to the revaluation).

   Formula rates: Historically, Account 254 is not considered in formula rates. However, as stated above, the revaluation amount recorded in Account 254 must be considered to achieve rate base neutrality. FERC proposes that public utilities include a "mechanism" to adjust rate base for any excess or deficient ADIT. Additionally, no guidance has been given on the required "mechanism" as FERC recognizes that a one-size-fits-all approach is not appropriate policy and will instead let public utilities propose any necessary changes to their formula rates on an individual basis.

Unitil

FERC responded to comments suggesting to record the Excess Accumulated Deferred Income Taxes ("EDIT") in Accounts 281, 282, 283 stating that it had already addressed this topic in Docket No. AI93-5-000, at 8 (1993). EDIT should be recorded in Accounts 182.3 and 254 and no additional guidance is needed.

Management's Observation: *This proposed ruling requires continued monitoring as the newly settled Section 206 NETO Formula Rate Settlement (effective 1/1/2020) requires public utilities to exclude Accounts 182.3 and 254 and the exclusion of these accounts were a prominent item of discussion in the settlement deliberations.*

Stated rates: No new proposed rulings were issued regarding stated rates. FERC recognized the importance of adjusting rate base exclusively in base rate cases by stating:

> *"…while ADIT balances may have changed as a result of the Tax Cuts and Jobs Act, so too will many other aspects of the cost of service and calculations that underlie the stated rate, making it difficult to re-evaluate ADIT and its effect on rate base following a change in tax rates* ***without fully evaluating a public entity's entire cost of service and rates****"*

Management's Observation: *The Company's regulatory position for EDIT treatment in distribution base rates is supported by this statement (Order No. 475, FERC Stats. & Regs. ¶ 30,752 at 30,736).*

2. RETURN OF EXCESS ADIT TO OR RECOVERY OF DEFICIENT ADIT FROM RATEPAYERS.

Throughout the issued NOPRs and Policy Statement, the FERC was clear that the excess ADIT to be flowed back to rate payers was the portion of *"…an ADIT liability that was collected from customers…" (PL19-2-000 Page 2 Paragraph 3)* and that the following methods were to be followed in flowing the excess ADIT back to ratepayers so that *"…ratepayers whho contributed to excess ADIT balances will receive the benefit of the TCJA" (NOPR Docket No. RM19-5-000 Page 3 Paragraph 3).*

The two acceptable normalization methods for public utilities to use to flow back EDIT to ratepayers are: Average Rate Assumption Method ("ARAM") and Reverse South Georgia Method ("RSGM"). The TCJA requires public utilities to use the ARAM method if possible on protected ADIT but does not specify which method should be used on unprotected ADIT. The basis of both methods is to flow back EDIT to ratepayers according to the underlying book/tax timing difference remaining life. The FERC noted that the TCJA states that public utilities are to flow back protected EDIT no more rapidly than ARAM requires.

Management's Observation: ARAM amortization is the fastest EDIT can be flowed back to ratepayers. If beneficial, proposing slower ARAM amortization for EDIT flow back is not a normalization or regulatory violation and can be considered in future base rate cases.

Concerns were raised by the Office of Consumer Advocate ("OCA") that situations exist in formula and stated rates where a portion of the EDIT is flowed back through a public utility's earnings prior to the amortization being approved in base rates. As a result this amount that is flowed back prior to approved base rates would orphan the EDIT and ratepayers would never realize the resulting benefit. FERC recognized this possibility and explicitly stated that while EDIT might be allowed to be flowed back under ARAM it does not remove a public utility's obligation to return the EDIT. Stating:

> *"Any amounts allowed to be returned under the Average Rate Assumption Method schedule prior to the effective date of proposed tariff provisions made in compliance with the Proposed Rule should still be refunded to customers".*

Management's Observation: This is consistent with the Company's regulatory and accounting policy to record ARAM amortization only when it is approved in base rates.

Formula rates: FERC proposes a requirement to include a "mechanism" which decreases or increases their income tax allowances by any amortized excess or deficient

Unitil

ADIT, respectively. This amortization will reduce income tax allowances in formula rates no more rapidly than what is allowed by ARAM or RSGM.

Management's Observation: FGE's ARAM schedule has started and is therefore eligible to start including ARAM amortization in its next Internal Transmission Formula Rate filing.

Stated rates: FERC proposes to require public utilities to (1) determine the excess and deficient income tax caused by the TCJA, and (2) return this amount to or recover this amount from ratepayers. Additionally, the FERC proposes the use of the ADIT approved in the last base rate case to calculate EDIT to be flowed back to ratepayers. This method is believed to satisfy concerns to preserve costs of service as accepted in the last rate case.

Management's Observation: This is a departure from the Company's current regulatory position for stated transmission and distribution base rates. The Company has proposed delaying EDIT amortization until the next base rate case after the ARAM schedule starts.

3. SUPPORT FOR EXCESS AND DEFICIENT ADIT CALCULATION AND AMORTIZATION.

Formula rates: FERC proposes to require public utilities to incorporate a new permanent worksheet in their transmission formula rates that will annually track information related to excess or deficient ADIT to promote transparency. This worksheet will be required to be provided on an annual basis. This worksheet will contain at a minimum: (1) how many ADIT accounts were re-measured and the EDIT associated with them, (2) the accounting of any excess or deficient amounts in Accounts 182.3 and 254, (3) Whether the EDIT is protected or unprotected, (4) the accounts to which the EDIT are amortized, and (5) the amortization period of the EDIT being flowed back through rates.

Stated rates: No additional rules were proposed for stated rates. FERC believes that existing regulations are sufficient in supporting all EDIT flow back effects on public utilities cost of service calculations.

PL19-2-000: The FERC issued accounting guidance in the Policy Statement relative to recording EDIT on the balance sheet and income statement and ADIT associated with any sold or retired assets.

Accounting Recordation Guidance: As stated in NOPR-RM19-5-000 FERC has previously issued guidance on the accounting for EDIT in Docket No. AI93-5-000. FERC affirmed this guidance and stated that Accounts 182.3 and 254 are appropriate to record EDIT in for accounting and regulatory purposes. Additionally, FERC clarified that the amortization of EDIT should be recorded in a public utilities statement of earnings in Account 410.1 (debits) and 411.1 (credits) as appropriate. The FERC acknowledge that Account 407.3 and 407.4 is available to use for the offsetting amortization of Accounts 182.3 and 254 when specific identification of the particular source of the regulatory assets and liabilities cannot be made. However, the in this situation, the regulatory assets and liabilities recorded in Account 182.3 and 254 are a result of a change in tax law and tax rates making specific identification of the source of these amounts possible. As a result, it is deemed appropriate to record the offsetting amortization to Accounts 410.1 and 411.1 which are specifically designated for the recordation of ADIT.

Management's Observation: The Company is currently recording EDIT in compliance with AI93-5-000 and will record the associated EDIT amortization in Accounts 410.1 and 411.1 as appropriate.

ADIT associated with any sold or retired assets: Certain commenters to the FERC's initial NOI argued that ADIT associated with assets that are retired or sold no longer exists and therefore the public utility no longer needs to flow the EDIT associated with assets back either. This argument is made with a 2006 IRS Private Letter Ruling No. PLR-168537-02 which prohibits the flow back of ADIT to ratepayers of ADIT associated with retired or sold assets. The IRS stated that ADIT ceases to exist as of the date of the sale and subsequently there is nothing to flow back to ratepayers. FERC again referenced previously issued Docket No. AI93-5-000 and stated:

> *"…because these deficient ADIT and excess ADIT balances can no longer be characterized as deferred tax amounts to be settled with the IRS, the sale or retirement of any assets as of January 1, 2018 would not automatically reverse these balances as tax timing differences."*

For these assets there are two associated balances: (1) the ADIT balance based on the 21% tax rate that will be owed to the IRS and (2) EDIT balances resulting from the revalued ADIT that will not be payable to the IRS upon the sale of the asset. While the ADIT balance that needs to be settled with the IRS upon the sale or retirement of an asset, the EDIT balance is more reflective of a regulatory asset or liability.

FERC further clarified that EDIT recorded in Accounts 182.3 and 254 continue to exist as regulatory assets and liabilities, respectively, after an assets has been retired or sold and do not transfer to the purchaser of the utility plant asset. Therefore, the EDIT associated with the retirements or sale of an asset should continue to be recorded in Accounts 182.3 and 254 and be considered in the calculation of rate base.

Management's Observation: *This Company's regulatory policy regarding EDIT associated with the retirement and sale of utility assets comply with this Policy Statement.*

MANAGEMENT'S CONCLUSION:

Management met in December of 2018 to review the proposed NOPRs and Policy Statement with members from the Company's regulatory, accounting, finance and tax departments. The following action items were discussed and agreed upon:

1. Journalize FGE's Electric distribution and internal transmission EDIT for yearend report purposes - Tax
2. Research and prepare compliance filing due 90 days after final NOPRs for formula rates (FGE) – Tax & Regulatory

3. Research and prepare compliance filing due 90 days after final NOPRs for stated rates (GSGT) – Tax & Regulatory
4. Prepare additional back up required to be submitted with formula rates (FGE) – Tax & Regulatory

Management concludes that the Company will be ready to meet all compliance requirements after the final NOPRs are issued.

165 FERC ¶ 61,117
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35.24

[Docket No. RM19-5-000]

Public Utility Transmission Rate Changes to Address Accumulated Deferred Income Taxes

(Issued November 15, 2018)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is proposing to require all public utility transmission providers with transmission rates under an Open Access Transmission Tariff (OATT), a transmission owner tariff, or a rate schedule to revise those rates to account for changes caused by the Tax Cuts and Jobs Act of 2017 (Tax Cuts and Jobs Act). Specifically, for transmission formula rates, the Commission is proposing to require that public utilities deduct excess accumulated deferred income taxes (ADIT) from or add deficient ADIT to their rate bases and adjust their income tax allowances by amortized excess or deficient ADIT. The Commission is also proposing to require all public utilities with transmission formula rates to incorporate a new permanent worksheet into their transmission formula rates that will annually track ADIT information. Additionally, the Commission is proposing to require all public utilities with transmission stated rates to determine the amount of excess and deferred income tax

caused by the Tax Cuts and Jobs Act's reduction to the federal corporate income tax rate and return or recover this amount to or from customers.

DATES: Comments are due **[INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**

ADDRESSES: Comments, identified by docket number, may be filed electronically at http://www.ferc.gov in acceptable native applications and print-to-PDF, but not in scanned or picture format. For those unable to file electronically, comments may be filed by mail or hand-delivery to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, N.E., Washington, D.C. 20426. The Comment Procedures Section of this document contains more detailed filing procedures.

FOR FURTHER INFORMATION CONTACT:

Noah Lichtenstein (Technical Information)
Office of Energy Market Regulation
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(202) 502-8696
noah.lichtenstein@ferc.gov

Joshua Walters (Legal Information)
Office of the General Counsel
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(202) 502-6098
joshua.walters@ferc.gov

SUPPLEMENTARY INFORMATION:

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Public Utility Transmission Rate Changes to Address Accumulated Deferred Income Taxes — Docket No. RM19-5-000

NOTICE OF PROPOSED RULEMAKING

TABLE OF CONTENTS

Paragraph Numbers

165 FERC ¶ 61,117
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Public Utility Transmission Rate Changes to Address Accumulated Deferred Income Taxes — Docket No. RM19-5-000

NOTICE OF PROPOSED RULEMAKING

(Issued November 15, 2018)

1. In this Notice of Proposed Rulemaking (Proposed Rule), we are proposing to require all public utility transmission providers with transmission rates under an Open Access Transmission Tariff (OATT), a transmission owner tariff, or a rate schedule to revise those rates to account for changes caused by the Tax Cuts and Jobs Act of 2017 (Tax Cuts and Jobs Act).[1] These proposed reforms are designed to address the effects of the Tax Cuts and Jobs Act on the Accumulated Deferred Income Taxes (ADIT) reflected in all transmission rates under an OATT, a transmission owner tariff, or a rate schedule of public utility transmission providers. The proposed reforms are intended to ensure that

[1] An Act to provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018, Pub. L. No. 115-97, 131 Stat. 2054 (2017) (Tax Cuts and Jobs Act). In proposing this new requirement, the Commission relies on existing Commission regulations relating to tax normalization for public utilities as those regulations apply to public utilities with transmission formula or stated rates. *See* 18 CFR 35.24. In this Proposed Rule, the Commission does not propose any generic reforms as to non-public utilities or the non-transmission rates of public utilities. While any conclusions that the Commission makes in this proceeding may be relevant to such rates, they will be addressed on a case-by-case basis. Furthermore, to the extent any entity believes that the Tax Cuts and Jobs Act renders any existing Commission-jurisdictional rate unjust and unreasonable, that entity may submit a complaint to the Commission.

ratepayers receive the benefits of the Tax Cuts and Jobs Act, and that the public utility transmission formula and stated rates are just and reasonable and not unduly discriminatory or preferential following the enactment of the Tax Cuts and Jobs Act. The proposed reforms are also intended to ensure that transmission formula and stated rates meet the Commission's tax normalization requirements such that the income tax component of those rates is calculated as though the taxable income were recognized in the same period and amount by the Internal Revenue Service (IRS) and the Commission.[2]

2. The proposed reforms generally fall into three categories and apply to public utilities with transmission formula rates and stated rates in different ways. First, we propose to require all public utilities with transmission formula rates to include a mechanism in their formula rates to deduct any excess ADIT from or add any deficient ADIT to their rate bases. This will ensure that rate base continues to be treated in a manner similar to that prior to the Tax Cuts and Jobs Act (i.e., that rate base neutrality is preserved). As for public utilities with transmission stated rates, we do not propose any new requirements regarding rate base neutrality.

3. Second, we propose to require all public utilities with transmission formula rates to include a mechanism in their formula rates that decreases or increases their income tax

[2] In this Proposed Rule, the Commission refers to comments filed in response to the Notice of Inquiry issued March 15, 2018. *Inquiry Regarding the Effect of the Tax Cuts and Jobs Act on Commission-Jurisdictional Rates*, FERC Stats. & Regs. ¶ 35,582 (2018) (NOI). A list of commenters in that proceeding and the abbreviated names used in this Proposed Rule appears in Appendix A. Any comments to this Proposed Rule should be filed in this proceeding, Docket No. RM19-5-000.

allowances by any amortized excess or deficient ADIT, respectively. This reform will help to ensure that public utilities with transmission formula rates return excess ADIT to or recover deficient ADIT from ratepayers. As a result, ratepayers who contributed to excess ADIT balances will receive the benefit of the Tax Cuts and Jobs Act.

4. With regard to public utility transmission providers with stated rates, we are proposing to require these entities to determine the excess and deficient ADIT caused by the Tax Cuts and Jobs Act based on the ADIT amounts approved in their last rate case and then to return this amount to or recover this amount from customers. This reform is intended to increase the likelihood that those customers who contributed to the related ADIT accounts receive the benefits of the Tax Cuts and Jobs Act.

5. Third, we propose to require all public utilities with transmission formula rates to incorporate a new permanent worksheet into their transmission formula rate that will annually track information related to excess or deficient ADIT. We believe that this reform will increase the transparency surrounding the adjustment of rate bases and income tax allowances to account for excess or deficient ADIT by public utilities with transmission formula rates. We do not propose any additional worksheets for public utilities with transmission stated rates because we believe that existing regulations require sufficient transparency.

6. We seek comments on these proposed reforms and areas for further comment within 30 days after publication of this Proposed Rule in the *Federal Register*.

I. <u>Background</u>

A. <u>Tax Cuts and Jobs Act</u>

7. On December 22, 2017, the President signed into law the Tax Cuts and Jobs Act. The Tax Cuts and Jobs Act, among other things, reduced the federal corporate income tax rate from 35 percent to 21 percent, effective January 1, 2018. This means that, beginning January 1, 2018, companies subject to the Commission's jurisdiction will compute income taxes owed to the IRS based on a 21 percent tax rate. The tax rate reduction will result in less corporate income tax expense going forward.[3]

8. Importantly, the tax rate reduction will also result in a reduction in ADIT liabilities and ADIT assets on the books of rate-regulated companies. ADIT balances are accumulated on the regulated books and records of public utilities based on the requirements of the Uniform System of Accounts. ADIT arises from timing differences between the method of computing taxable income for reporting to the IRS and the method of computing income for regulatory accounting and ratemaking purposes.[4] As a result of the Tax Cuts and Jobs Act reducing the federal corporate income tax rate from 35 percent to 21 percent, a portion of an ADIT liability that was collected from customers will no longer be due from public utilities to the IRS and is considered excess ADIT, which must be returned to customers in a cost of service ratemaking context. Additionally, for public utilities that have an ADIT asset, the Tax Cuts and Jobs Act will

---

[3] *See* Tax Cuts and Jobs Act, Sec. 13001, 131 Stat. at 2096.

[4] *See* 18 CFR 35.24(d)(2).

result in a reduction to that ADIT asset, and public utilities may seek to reflect in rates a portion of such reductions. Public utilities are required to adjust their ADIT assets and ADIT liabilities for the effect of the change in tax rates in the period that the change is enacted.[5]

B. <u>Overview of Public Utility Transmission Rates</u>

9. The Commission is responsible for ensuring that the rates, terms and conditions of service for wholesale sales and transmission of electric energy in interstate commerce are just, reasonable, and not unduly discriminatory or preferential. With respect to the transmission of electric energy in interstate commerce, most jurisdictional entities are subject to cost of service regulation. Cost of service regulation seeks to allow public utilities the opportunity to (1) recover operating costs, including income taxes, (2) recover the cost of capital investments, and (3) earn a just and reasonable return on investments.[6] Public utilities have calculated their cost of service-based transmission rates predominately by using formula rates or stated rates. These rates are contained in numerous agreements, including a public utility's OATT, a regional transmission operator's or independent system operator's OATT, coordination agreements, and wholesale distribution agreements. In this Proposed Rule, we focus on all public utilities

[5] *See* 18 CFR 35.24 and 18 CFR 154.305; *see also Regulations Implementing Tax Normalization for Certain Items Reflecting Timing Differences in the Recognition of Expenses or Revenues for Ratemaking and Income Tax Purposes*, Order No. 144, FERC Stats. & Regs. ¶ 30,254 (1981), *order on reh'g*, Order No. 144-A, FERC Stats. & Regs. ¶ 30,340 (1982).

[6] *See Pub. Sys. v. FERC*, 709 F.2d 73, 75 (D.C. Cir. 1983).

with transmission formula or stated rates that are contained in an OATT, a transmission owner tariff, or a rate schedule.

10. When a public utility uses stated rates, if the public utility seeks to change its rate, it files a rate case at the Commission to establish the cost of service revenue requirement, allocate costs to various customer groups, and calculate rates. As an alternative, the Commission permits public utilities to establish rates through formulas, in which the Commission accepts the public utility's cost of service calculation methodologies and input sources and allows the public utility to update those inputs every year.

11. Public utilities must seek changes to their transmission stated rates or formula rates through filings with the Commission under section 205 of the Federal Power Act (FPA),[7] while the Commission and third parties can challenge a rate in a proceeding initiated under section 206 of the FPA.[8]

C. Order No. 144 and 18 CFR 35.24

12. The purpose of tax normalization is to match the tax effects of costs and revenues with the recovery in rates of those same costs and revenues.[9] As noted above, timing differences may exist between the method of computing taxable income for reporting to the IRS and the method of computing income for regulatory accounting and ratemaking

[7] *See* 16 U.S.C. 824d.

[8] *See* 16 U.S.C. 824e(a).

[9] Order No. 144, FERC Stats. & Regs. ¶ 30,254 at 31,522, 31,530.

purposes. The tax effects of these differences are placed in a deferred tax account to be used in later periods when the differences reverse.[10]

13. The Commission established this policy of tax normalization in Order No. 144 where it required use of "the provision for deferred taxes [(i.e., ADIT)] as a mechanism for setting the tax allowance at the level of current tax cost."[11] In keeping with this normalization policy, and as relevant to the Tax Cuts and Jobs Act's reduction of the federal corporate income tax rate, the Commission in Order No. 144 also required adjustments in the ADIT of public utilities' cost of service when excessive or deficient ADIT has been created as a result of changes in tax rates.[12] Furthermore, the Commission required "a rate applicant to compute the income tax component in its cost of service by making provision for any excess or deficiency in its deferred tax reserves resulting . . . from tax rate changes."[13] The Commission required that such provision be consistent with a Commission-approved ratemaking method made specifically applicable to the rate applicant.[14] Where no ratemaking method has been made specifically

[10] *Id.* at 31,554.

[11] *Id.* at 31,530.

[12] *Id.* at 31,519.

[13] Order No. 144, FERC Stats. & Regs. ¶ 30,254 at 31,560. *See also* 18 CFR 35.24(c)(1)(ii); 18 CFR 35.24(c)(2).

[14] Order No. 144, FERC Stats. & Regs. ¶ 30,254 at 31,560. *See also* 18 CFR 35.24(c)(3).

applicable, the Commission required the rate applicant to advance some method in its next rate case.[15] The Commission stated that it would determine the appropriateness of any proposed method on a case-by-case basis, but as the issue is resolved in a number of cases, a method with wide applicability may be adopted.[16] The Commission codified the requirements of Order No. 144 in its regulations in 18 CFR 35.24.[17]

D. Notice of Inquiry

14. Following the enactment of the Tax Cuts and Jobs Act, the Commission issued the NOI seeking comments on, among other things, whether, and if so, how, the Commission should address the effects of the Tax Cuts and Jobs Act on ADIT.[18] The Commission noted that the Tax Cuts and Jobs Act's reduction to the federal corporate income tax rate would potentially create excess or deficient ADIT on the books of public utilities.[19] As relevant to the reforms proposed in this Proposed Rule, the Commission sought comments on the preservation of rate base neutrality and how public utilities should make

---

[15] Order No. 144, FERC Stats. & Regs. ¶ 30,254 at 31,560.

[16] *Id*. *See also* 18 CFR 35.24(c)(3).

[17] Originally promulgated as part of Order 144, the regulatory text was redesignated as 18 CFR 35.25 in Order No. 144-A. *See* Order No. 144-A, FERC Stats. & Regs. ¶ 30,340 at 30,140. In Order No. 545, the Commission again redesignated the regulatory text to its present designation as 18 CFR 35.24. *See Streamlining Electric Power Regulation*, Order No. 545, FERC Stats. & Regs. ¶ 30,955, at 30,713 (1992) (cross-referenced at 61 FERC ¶ 61,207).

[18] NOI, FERC Stats. & Regs. ¶ 35,582.

[19] *Id.* P 13.

related adjustments to their rate bases for excess and deficient ADIT.[20] The Commission also sought comment on how public utilities should adjust their income allowances to return or recover excess or deficient ADIT, respectively,[21] as well as the method used to return or recover excess or deficient protected and unprotected ADIT.[22] Finally, the Commission sought comment on whether it should require public utilities to provide to the Commission, on a one-time basis, additional information to show the computation of excess or deficient ADIT and the corresponding return of excess ADIT to customers or recovery of deficient ADIT from customers. If so, the Commission also sought comments on what types of information public utilities should provide.[23]

II. <u>Discussion</u>

15. Since the issuance of Order No. 144, the landscape of public utility transmission rates has changed dramatically; that is, the vast majority of public utilities now use formula rates rather than stated rates. As described above, unlike stated rates, which are updated only through a rate case initiated by a FPA section 205 application by the public

[20] *Id.* PP 14-15.

[21] *Id.* P 21.

[22] *Id.* PP 17, 19. In the NOI, the Commission referred to “plant-based” and “non-plant based” ADIT. We agree with commenters’ recommendation to follow the IRS terminology of “protected” and “unprotected” ADIT instead of “plant-based” and “non-plant based” presented in the NOI. The IRS terms for “protected” and “unprotected” are directly associated with the IRS’ normalization protections to ensure a tax payer maintains the benefit of accelerated depreciation over the life of the related asset. Accordingly, we have changed the terms used in this Proposed Rule to better mirror IRS terminology.

[23] *Id.* P 23.

utility or an FPA section 206 action by the Commission or a complaining third party, inputs to formula rates are updated annually to derive a charge assessed to customers. Thus, a rate case no longer remains the appropriate vehicle for formula rates to reflect excess or deficient ADIT in a public utility's cost of transmission service, as contemplated by Order No. 144. The public utility's transmission formula rate should include provisions that accurately reflect excess or deficient ADIT in a public utility's cost of transmission service during the annual updates of the rest of the revenue requirement.

16. Following the NOI, we have determined that this near-industry-wide transition from stated to formula rates has caused a gap in the transmission formula rates of public utilities such that many, if not most, of those rates do not contain provisions to fully reflect any excess or deficient ADIT following a change in tax rates, as required by Order No. 144 and the Commission's regulations in 18 CFR 35.24. Two components are necessary to maintain an accurate cost of service following a change in income tax rates, such as that caused by the Tax Cuts and Jobs Act: (1) preservation of rate base neutrality through the removal of excess ADIT from or addition of deficient ADIT to rate base; and **(2)** the return of excess ADIT to or recovery of deficient ADIT from ratepayers.[24]

17. A review of public utility transmission formula rates suggests that only some transmission formula rates contain the first component, while even fewer contain the

[24] *Id.* P 13. While the Tax Cuts and Jobs Act decreased the federal corporate income tax rate, the reforms proposed in this Proposed Rule are also meant to ensure that transmission formula rates reflect the effects of tax increases, as well.

second. Consequently, as discussed in greater detail below, we propose to require public utilities with transmission formula rates to revise those rates to include these two components. Additionally, to provide greater transparency, we propose to require all public utilities with transmission formula rates to incorporate a new permanent worksheet into their transmission formula rates that will annually track ADIT information related to these two components.

18. Regarding public utilities with transmission stated rates, we propose maintaining Order No. 144's requirement that such public utilities reflect any adjustments made to their ADIT balances as a result of the Tax Cuts and Jobs Act (and any future tax changes) in their next rate case. However, to increase the likelihood that those customers who contributed to the related ADIT accounts receive the benefit of the Tax Cuts and Jobs Act, we propose to require public utilities with transmission stated rates to (1) determine any excess or deficient ADIT caused by the Tax Cuts and Jobs Act and (2) return or recover this amount to or from customers. We believe that the Commission's existing regulations already require all of the information necessary to support the changes proposed herein to reflect the effects of the Tax Cuts and Jobs Act on a transmission stated rate. Therefore, we propose not to require any additional worksheets.

19. The Commission generally does not permit single-issue ratemaking. However, similar to the Commission's actions following the Tax Cuts and Jobs Act,[25] given the

---

[25] *See AEP Appalachian Transmission Company, Inc*., 162 FERC ¶ 61,225 (2018); *Alcoa Power Generating Inc.—Long Sault Division*, 162 FERC ¶ 61,224 (2018).

limited scope of the reforms proposed here, we propose that compliance filings made in response to this Proposed Rule's final requirements may be considered on a single-issue basis.[26]

A. Ensuring Rate Base Neutrality

1. NOI

20. In the NOI, the Commission sought comment on how to ensure that rate base continues to be treated in a manner similar to that prior to the Tax Cuts and Jobs Act (i.e., how to preserve rate base neutrality), until excess and deficient ADIT have been fully returned or recovered in a just and reasonable manner. The Commission also sought comment on whether, and if so how, public utilities should make adjustments to rate base to reflect excess and deficient ADIT. The Commission asked that commenters address both formula rates and stated rates.[27]

2. Comments

21. Numerous public utilities and other commenters assert that, in order to preserve rate base neutrality, unamortized balances of excess ADIT must continue to be treated as an offset to (i.e., a deduction from) rate base until those balances are flowed back in their

---

[26] *See generally Indicated RTO Transmission Owners*, 161 FERC ¶ 61,018, at PP 13-14 (2017); s*ee also Rates Changes Relating to the Federal Corporate Income Tax Rate for Public Utilities*, Order No. 475, FERC Stats. & Regs. ¶ 30,752, *order on reh'g*, 41 FERC ¶ 61,029 (1987) (allowing public utilities to use a voluntary, abbreviated rate filing procedure to reduce their rates to reflect a reduction in the federal corporate income tax rate on a single-issue basis).

[27] NOI, FERC Stats. & Regs. ¶ 35,582 at PP 14-15.

entirety to customers.[28] These commenters generally note that, following the passage of the Tax Cuts and Jobs Act, public utilities transferred excess ADIT to Account 254 (Other Regulatory Liabilities) or Account 182.3 (Other Regulatory Assets), as appropriate.[29] Accordingly, these commenters state that, just as the ADIT balances were deducted from or added to rate base, as appropriate, the corresponding amounts recorded in Accounts 254 and 182.3 should be deducted from or added to rate base. While generally agreeing that rate base adjustments are necessary, several commenters assert that there is no "one-size fits all" solution.[30]

[28] APPA and AMP, Comments to NOI, Docket No. RM18-12-000, at 4-7 (filed on May 22, 2018) (APPA and AMP NOI Comments); Avangrid, Comments to NOI, Docket No. RM18-12-000, at 5 (May 22, 2018) (Avangrid NOI Comments); Consumer Advocates, Comments to NOI, Docket No. RM18-12-000, at 4-5 (filed May 21, 2018) (Consumer Advocates NOI Comments); DEMEC, Comments to NOI, Docket No. RM18-12-000, at 8 (filed May 21, 2018) (DEMEC NOI Comments); Indicated Customers, Comments to NOI, Docket No. RM18-12-000, at 3-6 (filed May 21, 2018) (Indicated Customers NOI Comments); National Grid, Comments to NOI, Docket No. RM18-12-000, at 6-7 (filed May 21, 2018) (National Grid NOI Comments); New York Transco, Comments to NOI, Docket No. RM18-12-000, at 5 (filed May 22, 2018) (New York Transco NOI Comments); Oklahoma Attorney General, Comments to NOI, Docket No. RM18-12-000, at 4 (filed May 22, 2018) (Oklahoma Attorney General NOI Comments); PSEG, Comments to NOI, Docket No. RM18-12-000, at 4 (filed May 22, 2018) (PSEG NOI Comments).

[29] Avangrid NOI Comments at 5; EEI, Comments to NOI, Docket No. RM18-12-000, at 10 (filed May 22, 2018) (EEI NOI Comments).

[30] Kentucky Municipals, Comments to NOI, Docket No. RM18-12-000, at 3-5 (filed May 21, 2018) (Kentucky Municipals NOI Comments); Exelon, Comments to NOI, Docket No. RM18-12-000, at 11-12 (filed May 22, 2018) (Exelon NOI Comments); TAPS, Comments to NOI, Docket No. RM18-12-000, at 3 (filed May 21, 2018) (TAPS NOI Comments); Indicated Transmission Owners, Comments to NOI, Docket No. RM18-12-000, at 7 (filed May 21, 2018) (Indicated Transmission Owners NOI Comments) (("[t]here may be no uniform way to achieve the Commission's rate base

22. Regarding public utilities with formula rates, several commenters support the addition of a line item to formula rates for rate base adjustments reflecting excess or deficient ADIT recorded in Accounts 254 and 182.3.[31] Many of these commenters suggest that the Commission permit public utilities to make single-issue FPA section 205 filings to make the appropriate changes to their formula rates.[32] EEI suggests that the Commission should permit utilities with formula rates requiring adjustments to address these during their next true-up annual informational filing.[33]

23. Alternatively, APPA and AMP, and Indicated Customers suggest that any excess or deficient ADIT resulting from the implementation of the Tax Cuts and Jobs Act be recorded to the same ADIT accounts (e.g., Accounts 190, 281, 282, and 283) where the original entries for the regulatory assets and regulatory liabilities were established.[34] APPA and AMP state that by keeping the excess or deficient ADIT in sub-accounts

---

neutrality objective given differences between companies in accounting methods and rate structures.") (citation omitted)).

[31] Oklahoma Attorney General NOI Comments at 4-5; PSEG NOI Comments at 4; Avangrid NOI Comments at 5-9; Eversource, Comments to NOI, Docket No. RM18-12-000, at 4 (filed May 22, 2018) (Eversource NOI Comments); National Grid NOI Comments at 7-8; TAPS NOI Comments at 4.

[32] Eversource NOI Comments at 4-5; Indicated Transmission Owners NOI Comments at 6; PSEG NOI Comments at 4-5; National Grid NOI Comments at 7-8.

[33] EEI NOI Comments at 11.

[34] APPA and AMP NOI Comments at 7-8; Indicated Customers NOI Comments at 6-7.

within the original ADIT accounts, it will be more transparent and easier to track as the balances are flowed back.[35] As another alternative, the Oklahoma Attorney General asserts that the Commission should consider requiring that the line item currently used to offset rate base with ADIT include both ADIT balances in traditional ADIT-related accounts and those excess ADIT balances in other accounts identified by the Commission.[36]

24. Other commenters note that such a line item adjustment may not be necessary in all cases.[37] Specifically, these commenters assert that certain formula rates (e.g., certain MISO Attachment O, AEP, Exelon, and Eversource formula rates) already provide for the inclusion of excess ADIT in rate base and that the balances in Accounts 254 and 182.3 will naturally flow into rate base without any modification.[38]

25. Regarding public utilities with stated rates, commenters generally agree that adjustments are not necessary to preserve rate base neutrality with respect to stated

---

[35] APPA and AMP NOI Comments at 7-8.

[36] Oklahoma Attorney General NOI Comments at 4-5.

[37] Ameren, Comments to NOI, Docket No. RM18-12-000, at 7-8 (filed May 21, 2018) (Ameren NOI Comments); MISO Transmission Owners, Comments to NOI, Docket No. RM18-12-000, at 7 (filed May 21, 2018) (MISO Transmission Owners NOI Comments); EEI NOI Comments at 11; Exelon NOI Comments at 11-12.

[38] AEP, Comments to NOI, Docket No. RM18-12-000, at 3-4 (filed May 22, 2018) (AEP NOI Comments); Ameren NOI Comments at 7-8; MISO Transmission Owners NOI Comments at 7; Eversource NOI Comments at 3-4; Exelon NOI Comments at 11-12.

rates.[39] National Grid and Avangrid state that, under cost-of-service, both ADIT balances and regulatory liability balances should be deducted from rate base in calculating the stated rate.[40] Avangrid asserts that rate base neutrality issues are not raised with transmission stated rates because these rates assume the same amount of ADIT deduction to rate base without regard to how the companies adjusted their books and records.[41]

3. Proposed Requirements

a. Formula Rates

26. We propose to require all public utilities with transmission formula rates to include a mechanism in their formula rates which deducts any excess ADIT from or adds any deficient ADIT to their rate bases under 18 CFR 35.24. As described above, the Commission's regulations in 18 CFR 35.24 require public utilities to reflect any excess or deficient ADIT as a result of any changes in tax rates in their next rate case. As a result of the Tax Cuts and Jobs Act's reduction of the federal corporate income tax from 35 percent to 21 percent, public utilities have collected excess funds for their ADIT liabilities and have not collected sufficient funds for any ADIT assets. To preserve rate base neutrality by accurately matching the tax allowance with the current tax cost as required by Commission regulations, public utilities with transmission formula rates must

---

[39] National Grid NOI Comments at 7-8; Avangrid NOI Comments at 5-6; EEI NOI Comments at 11.

[40] National Grid NOI Comments at 7-8; Avangrid NOI Comments at 5-6.

[41] Avangrid NOI Comments at 5-6.

include provisions in their formula rates to adjust their ADIT for excess or deficient ADIT.[42] We believe our proposal will ensure that public utilities with transmission formula rates will adjust their ADIT for any excess or deficient ADIT caused by the Tax Cuts and Jobs Act or any future changes to tax rates which may give rise to excess or deficient ADIT.

27. While we are proposing to require public utilities with transmission formula rates to include a mechanism to adjust rate base for any excess or deficient ADIT, we are not proposing to prescribe a specific adjustment mechanism which applies to all public utilities with transmission formula rates. We agree with commenters to the NOI that prescribing a one-size-fits-all approach, such as adding a line item, is not appropriate and that the Commission should instead allow public utilities to propose any necessary changes to their formula rates on an individual basis. Recent filings and comments submitted in the NOI suggest that multiple approaches to modify rate base may be just and reasonable. For example, as noted by MISO Transmission Owners,[43] the Commission accepted proposals by ITC Companies and Ameren in which those companies did not revise their formula rates to modify their adjustments to rate base by adding a new line item for rate base.[44] Instead, those companies demonstrated that, while

[42] Order No. 144, FERC Stats. & Regs. ¶ 30,254 at 31,530, 31,519.

[43] MISO Transmission Owners NOI Comments at 7.

[44] *Midcontinent Indep. Sys. Operator, Inc.*, 153 FERC ¶ 61,374 (2015); *Midcontinent Indep. Sys. Operator, Inc.*, 163 FERC ¶ 61,163 (2018).

not visible in their formula rates, their adjustments to rate base were modified by any excess or deficient ADIT prior to their input to the formula rates. Accordingly, we also propose that public utilities with transmission formula rates may demonstrate that their formula rates already meet the proposed ADIT adjustment requirements described in this Proposed Rule.

28. We are not persuaded by commenters to the NOI who suggest that excess or deficient ADIT amounts should be recorded to the same ADIT accounts where the original entries for the regulatory assets and regulatory liabilities were established. The Commission previously issued guidance on this topic, finding that public utilities are required to record a regulatory asset (Account 182.3) associated with deficient ADIT or regulatory liability (Account 254) associated with excess ADIT.[45] As a result, we do not propose any changes to that specific accounting guidance.

b. Stated Rates

29. We do not propose any new requirements regarding rate base neutrality for public utilities with transmission stated rates. As noted by commenters to the NOI, stated rates are calculated based in large part on company data submitted, and projections made, at the time of the last rate case. Thus, while ADIT balances may have changed as a result of the Tax Cuts and Jobs Act, so too will many other aspects of the cost of service and calculations that underlie the stated rate, making it difficult to re-evaluate ADIT and its

[45] *See* Accounting for Income Taxes, Docket No. AI93-5-000, at 8 (1993).

effect on rate base following a change in tax rates without fully evaluating a public utility's entire cost of service and rates.[46] We believe that the revisions we are proposing below, related to the return or recovery of excess or deficient ADIT, will adequately address the effects of the Tax Cuts and Jobs Act on ADIT and will avoid such complications. Therefore, we do not propose to require adjustments to the rate bases of public utilities with transmission stated rates prior to their next rate case on a generic basis.

B. Return or Recovery of Excess or Deficient ADIT

1. NOI

30. In the NOI, the Commission asked commenters to address how public utilities with stated or formula rates should adjust their income tax allowance such that the allowance would be decreased or increased by the amortization of excess or deficient ADIT, respectively.[47] Additionally, the Commission asked commenters how the Average Rate Assumption Method, and alternatively, the Reverse South Georgia Method or South Georgia Method, as appropriate, will be implemented in the amortization of protected excess or deficient ADIT and how quickly to amortize unprotected excess or deficient ADIT.[48]

---

[46] The Commission previously acknowledged this difficulty in Order No. 475. Order No. 475, FERC Stats. & Regs. ¶ 30,752 at 30,736.

[47] NOI, FERC Stats. & Regs. ¶ 35,582 at P 21.

[48] *Id.* PP 17, 19. Under the South Georgia method, a calculation is taken of the difference between the amount actually in the deferred account and the amount that would have been in the account had normalization continuously been followed. Any

2. <u>Comments</u>

31. Commenters generally support adjusting public utilities' income tax allowances by the amortization of excess or deficient ADIT. Many commenters suggest adding a line item or several line items to public utility transmission formula rates to make this adjustment,[49] with some transmission owners noting that they have already submitted or now propose to submit such revisions.[50] MISO Transmission Owners note that the Commission accepted such a proposal by ITC Great Plains.[51] National Grid suggests that adjustments to income tax allowances could also be made through the weighted cost of capital.[52]

---

deficiency is collected from ratepayers (i.e., South Georgia Method), and any excess is returned to ratepayers (i.e., Reverse South Georgia Method), over the remaining depreciable life of the plant that caused the difference. *Memphis Light, Gas and Water Div. v. FERC*, 707 F.2d 565, 569 (D.C. Cir. 1983).

[49] Ameren NOI Comments at 15-16; Avangrid NOI Comments at 11-12; MISO Transmission Owners NOI Comments at 14-17; National Grid NOI Comments at 15; New York Transco NOI Comments at 10; Oklahoma Attorney General NOI Comments at 6; PSEG NOI Comments at 10.

[50] Ameren NOI Comments at 15-16; Avangrid NOI Comments at 11-12; MISO Transmission Owners NOI Comments at 16-17; New York Transco NOI Comments at 10.

[51] MISO Transmission Owners NOI Comments at 15 (citing *Midcontinent Indep. Sys. Operator, Inc.*, 153 FERC ¶ 61,374). *See also Midcontinent Indep. Sys. Operator, Inc.*, 163 FERC ¶ 61,163.

[52] National Grid NOI Comments at 15.

32. Commenters also support revisions to transmission stated rates to reflect income tax allowance adjustments for the amortization of excess or deficient ADIT.[53] TAPS states that, to address these adjustments, it supports an approach similar to utility-specific investigations the Commission opened with respect to the change in the federal corporate income tax rate.[54] However, TAPS expresses concern that stated rate customers will find it challenging to verify their utilities' calculation and asserts that, thus, the Commission should encourage utilities to work with customers toward a mutually acceptable solution and require those utilities to file the return mechanism, including detailed documentation and worksheets so that the calculation of excess ADIT can be validated.[55]

33. Some commenters caution the Commission against mandating that public utilities adopt a single method to adjust their formula rates' income tax allowances. Instead, these commenters suggest that the Commission recognize public utilities' specific circumstances by evaluating proposed modifications on a case-by-case basis or recognizing that some formula rates already adjust the income tax allowance by the amortization of excess or deficient ADIT and, therefore, would not require revision.[56]

---

[53] Avangrid NOI Comments at 9, National Grid NOI Comments at 15, TAPS NOI Comments at 6.

[54] TAPS NOI Comments at 6 (citing *Alcoa Power Generating Inc.—Long Sault Div.*, 162 FERC ¶ 61,224).

[55] TAPS NOI Comments at 5-7.

[56] Exelon NOI Comments at 14-15; Indicated Customers NOI Comments at 12-13; MISO Transmission Owners NOI Comments at 17.

Indicated Transmission Owners argue that the Commission should make any evaluations on a single-issue basis.[57] The Oklahoma Attorney General suggests that the Commission could use ongoing proceedings, such as the show cause proceedings initiated against public utilities whose formula rates would not automatically adjust to reflect the lower federal corporate income tax rate of 21 percent, to revise formula rates such that the income tax allowance is adjusted by the amortization of excess or deficient ADIT.[58]

34. Consumer Advocates are concerned that absent Commission intervention, jurisdictional entities may begin to amortize their excess ADIT, thereby denying customers the full benefit of the Tax Cuts and Jobs Act. Consumer Advocates argue that to the extent any protected ADIT balances have been amortized to date, the Commission should require such excess protected ADIT amortization credits to be reversed and the liability balance restored to that of the implementation date of the Tax Cuts and Jobs Act.[59]

35. Regarding protected excess or deficient ADIT, commenters agree that the Commission has no need to change its existing regulations or precedent or depart from the Tax Cuts and Jobs Act's normalization provisions.[60] Regarding unprotected excess or

[57] Indicated Transmission Owners NOI Comments at 11-12.

[58] Oklahoma Attorney General NOI Comments at 6.

[59] Consumer Advocates NOI Comments at 4.

[60] AEP NOI Comments at 4-5; Ameren NOI Comments at 11; APPA and AMP NOI Comments at 5-6, 10; Avangrid NOI Comments at 8-9; Consumer Advocates NOI Comments at 6-7; DEMEC NOI Comments at 9; EEI NOI Comments at 14, 16-17;

deficient ADIT, commenters agree that the Commission should adopt a case-by-case approach for determining how quickly excess or deficient unprotected ADIT should be flowed back to or recovered from customers.[61]

3. Proposed Requirements

a. Formula Rates

36. We propose to require all public utilities with transmission formula rates to include a mechanism in their formula rates which decreases or increases their income tax allowances by any amortized excess or deficient ADIT, respectively, under 18 CFR 35.24. Such a mechanism is necessary because, as described above, the Tax Cuts and Jobs Act's reduction of the federal corporate income tax rate from 35 percent to 21 percent means public utilities have collected from customers funds in excess of what is due to the IRS for ADIT liabilities and, conversely for ADIT assets, funds from customers insufficient to satisfy IRS tax obligations. Similar to the proposed rate base

Eversource NOI Comments at 7; Exelon NOI Comments at 13; Indicated Customers NOI Comments at 8-9; Indicated Transmission Owners NOI Comments at 8-9; Kentucky Municipals NOI Comments at 6; MISO Transmission Owners NOI Comments at 8-11; National Grid NOI Comments at 10-11; New York Transco NOI Comments at 7-8; Oklahoma Attorney General NOI Comments at 6-7; PSEG NOI Comments at 7-8.

[61] AEP NOI Comments at 6-7 ("However, in the event the Commission develops a broadly applicable amortization period, AEP recommends that period be 25 years or longer"); Avangrid NOI Comments at 9-11; Dominion, Comments to NOI, Docket No. RM18-12-000, at 12 (filed on May 21, 2018); EEI NOI Comments at 17-18; Enable Interstate Pipelines, Comments to NOI, Docket No. RM18-12-000, at 36-37 (filed on May 21, 2018); Enbridge and Spectra, Comments to NOI, Docket No. RM18-12-000, at 26 (filed May 21, 2018); EQT Midstream, Comments to NOI, Docket No. RM18-12-000, at 13-14 (filed May 21, 2018); Eversource NOI Comments at 8-9; Exelon NOI Comments at 13-14; Indicated Transmission Owners NOI Comments at 9-10; National Grid NOI Comments at 11-13; New York Transco NOI Comments at 9.

adjustment requirements, these proposed income tax allowance adjustment requirements are intended to satisfy Order No. 144's requirement that the income tax allowance match the current tax cost and reflect the effects of any future changes to tax rates that may give rise to excess or deficient ADIT.

37. Similar to comments regarding adjustments to rate base, we agree with commenters to the NOI that prescribing a one-size-fits-all approach is not appropriate and that the public utilities with transmission formula rates should instead be allowed to propose any necessary changes to their rates on an individual basis. Accordingly, we do not propose that all public utilities with transmission formula rates must use a single method to adjust their income tax allowances for any amortized excess or deficient ADIT. Many public utilities with transmission formula rates use different formats of rate templates or formulas, and a single, prescriptive method, such as the requirement of a single line item, may not fully capture or transparently convey the amortization of excess or deficient ADIT. Additionally, recent filings by public utilities that proposed revisions to their formula rate templates to reflect changes in income tax rates by, among other things, incorporating mechanisms to return excess ADIT demonstrate that company-specific variations are necessary.[62]

[62] *See, e.g., Midcontinent Indep. Sys. Operator, Inc.*, 153 FERC ¶ 61,374; *Midcontinent Indep. Sys. Operator, Inc.*, 163 FERC ¶ 61,163; *Midcontinent Indep. Sys. Operator, Inc.,* 164 FERC ¶ 61,113 (2018); *Emera Maine*, 165 FERC ¶ 61,086 (2018).

38. Regarding the period over which the amortization of excess or deficient ADIT must occur, we believe that public utilities should follow the guidance provided in the Tax Cuts and Jobs Act, where available. As noted by commenters to the NOI, the Tax Cuts and Jobs Act provides a method of general applicability and requires public utilities to return excess protected ADIT[63] no more rapidly than over the life of the underlying asset using the Average Rate Assumption Method, or, where a public utility's books and underlying records do not contain the vintage account data necessary, it must use an alternative method.[64] In contrast, the Tax Cuts and Jobs Act does not specify what method public utilities must use for excess or deficient unprotected ADIT. We agree with commenters to the NOI that, because such a determination depends on the specific facts and circumstances for each public utility, a case-by-case approach to amortizing excess or deficient unprotected ADIT remains appropriate.

39. Consumer Advocates are concerned that a portion of the amounts allowable to be returned to customers under the Average Rate Assumption Method schedule would not be refunded due to the fact that any proposed tariff provisions to return excess ADIT as a result of this Proposed Rule will not be effective until after January 1, 2018. We

[63] While the Tax Cuts and Jobs Act does not mention deficient protected ADIT specifically, we expect that public utilities will recover such deficient ADIT in the same manner prescribed for excess protected ADIT.

[64] Tax Cuts and Jobs Act, Sec. 13001(b)(6)(A), 131 Stat. at 2099. If a public utility must use an alternative method, Commission precedent provides that the public utility should use the Reverse South Georgia Method for excess ADIT or the South Georgia Method for deficient ADIT. *See Memphis Light, Gas and Water Div. v. FERC*, 707 F.2d at 569.

acknowledge that in applying a tax normalization method (e.g., the Average Rate Assumption Method), public utilities are required to develop a schedule removing ADIT from rate base and returning it to customers, effective January 1, 2018, using the fastest allowable method to return the excess ADIT under the IRS' normalization requirements. However, these requirements represent only the fastest allowable return schedule and do not remove a public utility's obligation to return the excess ADIT. Any amounts allowed to be returned under the Average Rate Assumption Method schedule prior to the effective date of proposed tariff provisions made in compliance with the Proposed Rule should still be refunded to customers. In other words, the full regulatory liability for excess ADIT should be captured in rates, beginning on the effective date of any proposed tariff provision. We do not believe that any specific reforms are necessary to accomplish this because public utilities should not amortize an excess ADIT regulatory liability for accounting purposes until it is included in ratemaking.[65]

b. Stated Rates

40. We propose to require all public utilities with transmission stated rates to (1) determine the excess and deficient income tax caused by the Tax Cuts and Jobs Act's reduction to the federal corporate income tax rate and (2) return this amount to or recover this amount from customers under 18 CFR 35.24. We also propose for public utilities

[65] The description of Account 182.3 (Other regulatory assets) states, "The amounts recorded in this account are generally to be charged, *concurrently with the recovery of the amounts in rates…*" (emphasis added). 18 CFR part 101, Account 182.3 (Other Regulatory Assets).

with transmission stated rates to calculate this excess or deficient ADIT using the ADIT approved in their last rate cases. We believe calculating excess or deficient ADIT in this manner will allow public utilities with transmission stated rates to preserve their costs of service as accepted in their last rate case. We are not seeking to propose a specific way for public utilities with transmission stated rates to return or recover the excess or deficient income taxes to ratepayers; rather, we will evaluate each proposal on an individual basis. We believe the proposed reforms will increase the likelihood that those customers who contributed to the related ADIT accounts receive the benefit of the Tax Cuts and Jobs Act.

41. TAPS expresses concern that the customers of public utilities with transmission stated rates will lack sufficient information to evaluate any proposals to return or recover excess or deficient ADIT, respectively. We note that the Commission's regulations require public utilities filing changes to transmission rates to identify the effect of tax changes on those rates.[66] Accordingly, we expect that public utilities with stated rates would include in their compliance filings resulting from this Proposed Rule supporting information necessary to identify, at minimum, the following: (1) how any ADIT accounts were re-measured and the excess or deficient ADIT contained therein; (2) the accounting of any excess or deficient amounts in Accounts 182.3 and 254; (3) whether the excess or deficient ADIT is protected or unprotected; (4) the accounts to which the

[66] 18 CFR 35.13; 18 CFR 35.24.

excess or deficient ADIT will be amortized; and (5) the amortization period of the excess or deficient ADIT to be returned or recovered through the rates.

42. Finally, as noted above, public utilities with transmission stated rates must conform to the Tax Cuts and Jobs Act's requirements regarding the period over which the amortization of protected excess or deficient ADIT must occur. We will continue to analyze the appropriate amortization period for unprotected ADIT on a case-by-case basis.

C. Support for Excess and Deficient ADIT Calculation and Amortization

1. NOI

43. In the NOI, the Commission sought comment on whether it should require public utilities to provide to the Commission, on a one-time basis, additional information, such as supporting worksheets, to show the computation of excess or deficient ADIT and the corresponding flow-back of excess ADIT to customers or recovery of deficient ADIT from customers. The Commission asked commenters to address what types of information public utilities already record for ADIT-related accounting and whether balances and amortization of regulatory liability and asset accounts, computation of excess and deficient ADIT, delineation between protected and non-protected ADIT, and a description of the allocation method used to determine the transmission-related portion of excess or deficient ADIT would be appropriate to include in a supporting worksheet.[67]

[67] NOI, FERC Stats. & Regs. ¶ 35,582 at P 23.

2. Comments

44. Commenters were split regarding the requirement to provide additional worksheets. Some commenters assert that the Commission should not require any additional worksheets at this time.[68] These commenters generally assert that the implementation of general worksheet requirements would be burdensome on the industry.[69] They assert that any data should only be required to be submitted on a company by company basis, as necessary, rather than require a one-time proceeding for the purpose of all public utilities providing the data showing whether and how ADIT balances were re-measured.[70] Certain commenters assert that the Commission should not require additional worksheets as transmission formula rates and associated protocols already include mechanisms to provide details to customers.[71] Avangrid similarly states that the formula rate processes should be used to provide the level of transparency to verify the flowback of excess ADIT ultimately prescribed by the Commission. EEI states that if the Commission does require additional supporting information as part of EEI's

[68] *See* AEP NOI Comments at 8; Ameren NOI Comments at 16-18; Avangrid NOI Comments at 13-14; EEI NOI Comments at 20-22; Exelon NOI Comments at 15; Indicated Transmission Owners NOI Comments at 12; MISO Transmission Owners NOI Comments at 18-19; and PSEG NOI Comments at 11-12.

[69] *See* EEI NOI Comments at 20-21; Exelon NOI Comments at 15.

[70] EEI NOI Comments at 20.

[71] *See* AEP NOI Comments at 8; Ameren NOI Comments at 16-17; Avangrid NOI Comments at 13-14; Exelon NOI Comments at 15, Indicated Transmission Owners NOI Comments at 12; and MISO Transmission Owners NOI Comments at 18-19.

proposed show cause orders, the Commission should first provide its proposed financial template, in a rulemaking, to allow for review by public utilities and stakeholders. EEI adds that this would reduce the burden on individual public utilities and the Commission and would be similar to the approach leading up to the Gas Tax Final Rule.[72]

45. Other commenters, however, assert that the Commission should require electric public utilities to provide a one-time filing of additional information to provide transparency regarding excess and deficient ADIT, and how rates will be impacted by any changes.[73] APPA and AMP urge the Commission to require that supporting information be filed regarding excess or deficient ADIT, but not be limited to only ADIT-related material. They assert that public utilities should also describe, with supporting schedules, any current or projected effects on their books associated with the Tax Cuts and Jobs Act's changes to bonus depreciation, or any other potential rate-related impacts.[74] APPA and AMP further state that for public utilities with transmission formula rates, the utilities should provide as part of their annual updates, calculations showing excess ADIT amortization amounts that should be flowed back to customers in the applicable rate period. Consumer Advocates state that in addition to requiring a

[72] EEI NOI Comments at 21, n. 36.

[73] *See* APPA and AMP NOI Comments at 17-18; Consumer Advocates NOI Comments at 10-11; DEMEC NOI Comments at 11-12; Eversource NOI Comments at 11; Indicated Customers NOI Comments at 15; National Grid NOI Comments at 15-16; and New York Transco NOI Comments at 11.

[74] APPA and AMP NOI Comments at 17-18.

detailed worksheet identifying all book tax timing differences that comprise deferred tax liability balances, the Commission should evaluate the build-up of net operating losses as deferred tax assets. They assert that such balances should not automatically be inserted as an addition to regulated rate base.[75] New York Transco states that each public utility should be permitted to compile and present this additional information in the manner it deems most efficient and useful for stakeholders. New York Transco states that if stakeholders desire additional information, any interested party can seek that information consistent with the formula rate implementation protocols that address information sharing. While not objecting to the provision of additional information, National Grid states that the Commission should not impose this requirement until after December 2018 as the additional information will not be meaningful until after companies have set the final rate change balance after the filing of their fiscal year 2018 federal corporate income tax returns.[76]

3. **<u>Proposed Requirements</u>**

a. **<u>Formula Rates</u>**

46. We propose to require all public utilities with transmission formula rates to incorporate a new permanent worksheet into their transmission formula rates that will annually track information related to excess or deficient ADIT under 18 CFR 35.24. We believe that this reform is necessary to provide interested parties adequate transparency

---

[75] Consumer Advocates NOI Comments at 10-11.

[76] National Grid NOI Comments at 16.

regarding how public utilities with transmission formula rates adjust their rate bases and income tax allowances to account for excess or deficient ADIT. We also believe that requiring public utilities with transmission formula rates to provide this information on an annual basis rather than a one-time basis will better allow interested parties to follow excess or deficient ADIT as it is included in an annual revenue requirement and provide transparency as to any future changes in tax rates. We also believe that updating the proposed worksheet annually will better align with the nature of the vast majority of formula rates where calculation methodologies and input sources are accepted prior to those inputs being populated. Consequently, we do not propose that any worksheet be populated when submitted to the Commission for compliance, only that the function of the worksheet be clear.

47. Similar to other reforms proposed in this Proposed Rule, we do not propose a pro forma worksheet that must be adopted by all public utilities with transmission formula rates; rather, we propose requiring general categories of information that each excess or deficient ADIT tracking worksheet must contain. We propose that each excess or deficient ADIT worksheet must, at minimum, include the following: (1) how any ADIT accounts were re-measured and the excess or deficient ADIT contained therein; (2) the accounting of any excess or deficient amounts in Accounts 182.3 and 254; (3) whether the excess or deficient ADIT is protected or unprotected; (4) the accounts to which the excess or deficient ADIT are amortized; and (5) the amortization period of the excess or deficient ADIT being returned or recovered through the rates. Because we do not propose to define the form any worksheet or worksheets must take, only the

information it must contain, we propose evaluating such worksheet or worksheets on an individual basis. We also request comments on whether we should consider additional guiding principles to those described above.

48. We disagree with commenters to the NOI that argue that providing such information is overly burdensome for the industry. Public utilities with transmission formula rates will already have gathered the information we propose to require in the worksheets to re-measure their ADIT balances and develop amortization schedules following the Tax Cuts and Jobs Act's reduction of the federal corporate income tax rate. Further, the Commission has already accepted worksheets that convey information similar to the proposed requirements outlined above.[77]

49. We also disagree with commenters to the NOI that public utilities' existing formula rate protocols should preclude the Commission from proposing an excess or deficient ADIT worksheet. While the Commission established that formula rate protocols should allow for the provision of any information necessary to understand the inputs to the rate in order to provide sufficient transparency to interested parties, the Commission has since required public utilities to revise their formula rates to include greater detail where it has deemed that certain inputs to the rate are complex enough to warrant prior understanding of their effect.[78] As related to excess and deficient ADIT,

---

[77] *See, e.g., Arizona Public Service Company*, Docket No. ER18-975-001 (May 22, 2018) (delegated order).

[78] *See, e.g., Midcontinent Indep. Sys. Operator, Inc.*, 153 FERC ¶ 61,374 at P 14 (directing certain transmission companies to revise their transmission formula rates to

we believe the proposed worksheet will allow interested parties to ensure they are receiving the benefits of the Tax Cuts and Jobs Act, as well as to track over time any changes in the rate effects of the tax change as, for example, assets are sold or retired.

b. Stated Rates

50. As described above in the proposal for return of excess ADIT or recovery of deficient ADIT, we believe that the Commission's existing regulations require public utilities with transmission stated rates to provide sufficient support for any proposed tax-related changes. As a result, we do not propose any additional information requirements for public utilities with transmission stated rates.

III. Proposed Compliance Procedures

51. We propose to require each public utility with transmission stated or formula rates to submit a compliance filing within 90 days of the effective date of any subsequent final rule in this proceeding to revise its transmission formula or stated rates, as necessary, to demonstrate that it meets the requirements set forth in any subsequent final rule.

52. Some public utilities with transmission formula rates may already have mechanisms in place in their rates that address the issues and concerns addressed by any subsequent final rule. Where these provisions would be modified by any subsequent final rule, the public utility must either comply with any subsequent final rule or demonstrate

---

include worksheets to ensure appropriate transparency). The Commission has also regularly required certain revisions to new formula rates to provide greater transparency. *See, e.g., Xcel Energy Sw. Transmission Co., LLC*, 149 FERC ¶ 61,182 (2014); *Xcel Energy Transmission Dev. Co., LLC*, 149 FERC ¶ 61,181 (2014); *Transource Wisconsin, LLC*, 149 FERC ¶ 61,180 (2014); *Transource Kansas, LLC,* 151 FERC ¶ 61,010 (2015).

that these previously approved variations continue to be consistent with or superior to the requirements of any subsequent final rule.

53. The Commission will assess whether each compliance filing satisfies the proposed requirements stated above and issue additional orders as necessary to ensure that each public utility with transmission stated or formula rates meets the requirements of the subsequent final rule.

IV. Information Collection Statement

54. The collection of information contained in this Proposed Rule is subject to review by the Office of Management and Budget (OMB) regulations under section 3507(d) of the Paperwork Reduction Act of 1995 (PRA).[79] OMB's regulations require approval of certain informational collection requirements imposed by an agency.[80] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

55. The reforms proposed in this Proposed Rule address public utilities that have transmission formula rates and transmission stated rates. The reforms related to transmission formula rates represent new requirements for these entities under the

[79] 44 U.S.C. 3507(d).

[80] 5 CFR 1320.11.

Commission's regulations in 18 CFR 35.24, which we believe are necessary because of the dramatic changes in the rate structure of the electric transmission industry since this provision was originally promulgated in 1981.[81] These new requirements would require each public utility with a transmission formula rate to revise its rate so that any excess or deficient ADIT is properly reflected in its revenue requirement following a change in tax rates, such as those established by the Tax Cuts and Jobs Act. Additionally, each public utility with a transmission formula rate would be required to incorporate a new permanent worksheet into its transmission formula rate to increase transparency.

56. The reforms required by this Proposed Rule will require each public utility with stated rates to calculate the excess and deficient ADIT caused by the Tax Cuts and Jobs Act and to return to or recover from customers those amounts. This reform is intended to increase the likelihood that customers who contributed to the excess ADIT balance timely receive the benefits of the Tax Cuts and Jobs Act.

57. The reforms proposed in this Proposed Rule would require compliance filings with the Commission by each public utility with transmission stated or formula rates to allow the Commission the opportunity to determine whether each such public utility met the requirements detailed in this Proposed Rule.

58. We anticipate the reforms proposed in this Proposed Rule, once implemented, would not significantly change currently existing burdens on an ongoing basis. With regard to those public utilities with transmission stated or formula rates that believe that

[81] *See* discussion *infra* Section II.E.

they already comply with the reforms proposed in this Proposed Rule, they could demonstrate their compliance in the filing required 90 days after the effective date of the final revision in this proceeding. We will submit the proposed reporting requirements to OMB for its review and approval under section 3507(d) of the Paperwork Reduction Act.[82]

59. While we expect the adoption of the reforms proposed in this Proposed Rule to provide significant benefits, the Commission understands that implementation can be a complex and costly endeavor. We solicit comments on the accuracy of provided burden and cost estimates and any suggested methods for minimizing the respondents' burdens.

60. Burden Estimate and Information Collection Costs: We believe that the burden estimates below are representative of the average burden on respondents. The estimated burden and cost for the requirements contained in this Proposed Rule follow.

[82] 44 U.S.C. 3507(d).

RM19-5-000 NOPR (Public Utility Transmission Rate Changes to Address Accumulated Deferred Income Taxes)						
	Number of Respondents (1)	Annual Number of Responses per Respondent (2)	Total Number of Responses (1)*(2)=(3)	Average Burden & Cost Per Response[83] (4)	Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)	Cost per Respondent ($) (5)÷(1)
Revising formula rates so that excess ADIT is deducted and/or deficient ADIT is added to rate base (one-time)[84]	106	1	106	8 hours; $736	848 hours; $78,016	$736
Revising formula rates so that any excess and/or deficient ADIT is amortized (one-time)	106	1	106	8 hours; $736	848 hours; $78,016	$736

[83] The loaded hourly wage figure (includes benefits) is based on the average of the occupational categories for 2017 found on the Bureau of Labor Statistics website (http://www.bls.gov/oes/current/naics2_22.htm):

Accountant (Occupation Code: 13-2011): $56.59

Management (Occupation Code: 11-0000): $94.28

Legal (Occupation Code: 23-0000): $143.68

Office and Administrative Support (Occupation Code: 43-0000): $41.34

These various occupational categories' wage figures are averaged and weighted equally as follows: ($94.28/hour + $61.55/hour + $66.90/hour + $143.68/hour) ÷ 4 = $91.60/hour. The resulting wage figure is rounded to $92.00/hour for use in calculating wage figures in the NOPR in Docket No. RM19-5-000.

[84] One-time burdens apply in Year One only. There will be no subsequent burden in Years 2 and beyond.

Revising transmission stated rates to return or recover excess or deficient ADIT (one-time)	31	1	31	15 hours; $1,380	465 hours; $42,780	$1,380
Requiring public utilities with transmission formula rates to incorporate a new permanent worksheet that will annually track ADIT information (one-time)	106	1	106	40 hours; $3,680	4,240 hours; $390,080	$3,680
Total (Stated Rates)[85]			**31**		**465 hours; $42,780**	
Total (Formula Rates)[86]			**318**		**5,936 hours; $546,112**	
TOTAL			**349**		**6,532 hours; $588,892**	

Cost to Comply: We have projected the total cost of compliance as follows:[87]

[85] Total for Public Utilities with Transmission Stated Rates

[86] Total for Public Utilities with Transmission Formula Rates

[87] For a public utility transmission provider with transmission formula rates, the costs for Year 1 would consist of filing proposed changes to its transmission formula rates, including the addition of a new permanent worksheet, with the Commission within 90 days of the effective date of the final revision plus initial implementation. The Commission does not expect any ongoing costs beyond the initial compliance in Year 1. For a public utility transmission provider with transmission stated rates, the costs for Year 1 would consist of filing proposed changes to its transmission stated rates that allow it to return to or recover from customers any excess or deficient ADIT caused by the Tax Cuts and Jobs Act with the Commission within 90 days of the effective date of the final revision plus initial implementation.

- Year 1: $546,112 ($5,152/utility) for public utilities with transmission formula rates; $42,780 ($1,380/utility) for public utilities with transmission stated rates.
- Year 2: $0

After Year 1, the reforms proposed in this Proposed Rule, once implemented, would not significantly change existing burdens on an ongoing basis.

Title: FERC-516, Electric Rate Schedules and Tariff Filings.

Action: Proposed revisions to an information collection.

OMB Control No.: 1902-0096

Respondents for this Proposal: Businesses or other for profit and/or not-for-profit institutions.

Frequency of Information: One-time during year one.

Necessity of Information: The Federal Energy Regulatory Commission makes this Proposed Rule to ensure that (1) rate base neutrality is preserved following enactment of the Tax Cuts and Jobs Act; (2) the reduction in ADIT on the books of rate-regulated companies that was collected from customers but is no longer payable to the IRS due to the Tax Cuts and Jobs Act is returned to or recovered from ratepayers consistent with general ratemaking principles; and (3) there is increased transparency for the process of excess and deficient ADIT calculation and amortization.

Internal Review: We have reviewed the proposed changes and have determined that such changes are necessary. These requirements conform to the Commission's need for efficient information collection, communication, and management within the energy industry. We have specific, objective support for the burden estimates associated with the information collection requirements.

61. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director], e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873. Comments concerning the collection of information and the associated burden estimate(s), may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395-0710, fax: (202) 395-7285]. Due to security concerns, comments should be sent electronically to the following e-mail address: oira_submission@omb.eop.gov. Comments submitted to OMB should include FERC-516 and OMB Control No. 1902-0096.

V. Environmental Analysis

62. We are required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[88] The actions proposed to be taken in this Proposed Rule fall within the categorical exclusion under section 380.4(a)(15) of the Commission's regulations. This

[88] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987) (cross-referenced at 41 FERC ¶ 61,284).

section provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classification, and services.[89] The revisions proposed in this Proposed Rule fall within the categorical exemptions provided in the Commission's regulations, and as a result neither an Environmental Impact Statement nor an Environmental Assessment is required.

VI. Regulatory Flexibility Act Certification

63. The Regulatory Flexibility Act of 1980 (RFA)[90] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities. The RFA does not mandate any particular outcome in a rulemaking. It only requires consideration of alternatives that are less burdensome to small entities and an agency explanation of why alternatives were rejected.

64. The Small Business Administration (SBA) revised its size standards (effective January 22, 2014) for electric utilities from a standard based on megawatt hours to a standard based on the number of employees, including affiliates. Under SBA's standards, some transmission owners will fall under the following category and

[89] 18 CFR 380.4(a)(15).

[90] 5 U.S.C. 601-612.

associated size threshold: electric bulk power transmission and control, at 500 employees.[91]

65. We estimate that the total number of public utility transmission providers with formula rates that would have to develop revisions to their formula rates, including the addition of a new permanent worksheet, and make compliance filings in response to this Proposed Rule is 106. Of these, we estimate that approximately 43 percent are small entities (approximately 46 entities). We estimate the average total cost to each of these entities will be $5,152 in Year 1 and $0 in subsequent years. In addition, we estimate that the total number of public utility transmission providers with stated rates that will have to calculate the excess and deficient income tax to return to or recover from customers is 31. Of these, we estimate that approximately 43 percent are small entities (approximately 13 entities). We estimate the average total cost to each of these entities will be between $1,380 in Year One and $0 in subsequent years. According to SBA guidance, the determination of significance of impact "should be seen as relative to the size of the business, the size of the competitor's business, and the impact the regulation has on larger competitors."[92] We do not consider the estimated burden to be a significant economic

[91] 13 CFR 121.201, Sector 22 (Utilities), NAICS code 221121 (Electric Bulk Power Transmission and Control).

[92] U.S. Small Business Administration, *A Guide for Government Agencies How to Comply with the Regulatory Flexibility Act*, at 18 (May 2012), https://www.sba.gov/sites/default/files/advocacy/rfaguide_0512_0.pdf.

impact. As a result, we certify that the revisions proposed in this Proposed Rule will not have a significant economic impact on a substantial number of small entities.

VII. Comment Procedures

66. We invite interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due [**INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER**]. Comments must refer to Docket No. RM19-5-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

67. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

68. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street N.E., Washington, DC, 20426.

69. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VIII. Document Availability

70. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, N.E., Room 2A, Washington D.C. 20426.

71. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

72. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202)502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

By direction of the Commission. Commissioner McIntyre is not voting on this order.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Note: Appendix A will not be published in the Federal Register.

Appendix A – List of Commenters to NOI

Short Name	Commenter
AEP	American Electric Power Service Corporation
Ameren	Ameren Services Company on behalf of Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois, and Ameren Transmission Company of Illinois
AOPL	Association of Oil Pipe Lines
APGA	American Public Gas Association
APPA and AMP	American Public Power Association and American Municipal Power, Inc.
Avangrid	Avangrid Networks, Inc.
Berkshire	Berkshire Hathaway Energy Pipeline Group
Boardwalk	Boardwalk Pipeline Partners LP
CAPP	Canadian Association of Petroleum Producers
Consumer Advocates	Office of the Attorney General of the Commonwealth of Massachusetts; the Ohio Consumers' Counsel; the Maryland Office of People's Counsel; the Nevada Bureau of Consumer Protection; the Delaware Division of the Public Advocate; the Pennsylvania Office of Consumer Advocate; the Citizens Utility Board of Wisconsin; and the Indiana Office of Utility Consumer Counselor
DEMEC	Delaware Municipal Electric Corporation, Inc.
Dominion Energy Gas Pipelines	Dominion Energy Transmission, Inc.; Dominion Energy Carolina Gas Transmission, LLC; Dominion Energy Quester Pipeline, LLC; Dominion Energy Overthrust Pipeline, LLC; and Questar Southern Trails Pipeline Company

EEI	Edison Electric Institute
Enable Interstate Pipelines	Enable Mississippi River Transmission, LLC and Enable Gas Transmission, LLC
Enbridge and Spectra	Enbridge Energy Partners, L.P. and Spectra Energy Partners, LP
EQT Midstream	EQT Midstream Partners, LP
Eversource	Eversource Energy Service Company
Exelon	Exelon Corporation
Indicated Customers	Central Electric Power Cooperative, Inc., North Carolina Electric Membership Corporation, Southern Maryland Electric Cooperative, Inc., and the New Jersey Division of Rate Counsel
Indicated Local Distribution Companies	Atmos Energy Corporation; the City of Charlottesville, Virginia; the City of Richmond, Virginia; the Easton Utilities Commission; Exelon Corporation; and Washington Gas Light Company
Indicated Transmission Owners	American Electric Power Service Corporation; Dominion Energy Services, Inc., on behalf of Virginia Electric and Power Company d/b/a Dominion Energy Virginia; Duquesne Light Company; Exelon Corporation; FirstEnergy Service Company, on behalf of American Transmission Systems, Incorporated; Jersey Central Power & Light Company; Mid-Atlantic Interstate Transmission, LLC; West Penn Power Company; The Potomac Edison Company; Monongahela Power Company; and PPL Electric Utilities Corp.
INGAA	Interstate Natural Gas Association of America
ITC Great Plains	ITC Great Plains, LLC
Kentucky Municipals	Frankfort Plant Board of Frankfort, Kentucky; Barbourville Utility Commission of the City of Barbourville, City; Utilities Commission of the City of Corbin; and the Cities of Bardwell, Berea, Falmouth, Madisonville, and Providence, Kentucky

Kinder Morgan Entities	Natural Gas Pipeline Company of America LLC; Tennessee Gas Pipeline Company, L.L.C.; Southern Natural Gas Company, L.L.C.; Colorado Interstate Gas Company, L.L.C.; Wyoming Interstate Company, L.L.C.; El Paso Natural Gas Company, L.L.C.; Mojave Pipeline Company, L.L.C.; Bear Creek Storage Company, L.L.C.; Cheyenne Plains Gas Pipeline Company, L.L.C.; Elba Express Company, L.L.C.; Kinder Morgan Louisiana Pipeline LLC; Southern LNG Company, L.L.C.; and TransColorado Gas Transmission Company LLC
Kinder Morgan Subsidiaries	SFPP, L.P.; Calnev Pipe Line, LLC; and Kinder Morgan Cochin, LLC
MISO Transmission Owners	Ameren Services Company, as agent for Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois and Ameren Transmission Company of Illinois; American Transmission Company LLC; Central Minnesota Municipal Power Agency; City Water, Light & Power (Springfield, IL); Cleco Power LLC; Cooperative Energy; Dairyland Power Cooperative; Duke Energy Business Services, LLC for Duke Energy Indiana, LLC; East Texas Electric Cooperative; Entergy Arkansas, Inc.; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy New Orleans, LLC; Entergy Texas, Inc.; Great River Energy; Indiana Municipal Power Agency; Indianapolis Power & Light Company; International Transmission Company d/b/a ITC*Transmission*; ITC Midwest LLC; Lafayette Utilities System; Michigan Electric Transmission Company, LLC; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Missouri River Energy Services; Montana-Dakota Utilities Co.; Northern Indiana Public Service Company LLC; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Prairie Power Inc.; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); Southern Minnesota Municipal Power Agency; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc.

National Grid	National Grid USA
Natural Gas Indicated Shippers	Aera Energy, LLC; Anadarko Energy Services Company; Apache Corporation; BP Energy Company; ConocoPhillips Company; Hess Corporation; Occidental Energy Marketing, Inc.; Petrohawk Energy Corporation; and XTO Energy, Inc.
New York Transco	New York Transco LLC
Oklahoma Attorney General	Mike Hunter, Oklahoma Attorney General
PJM	PJM Interconnection, L.L.C.
Plains	Plains Pipeline, L.P.
Process Gas and American Forest and Paper	Process Gas Consumers Group and American Forest and Paper Association
PSEG	Public Service Electric and Gas Company
Tallgrass Pipelines	Trailblazer Pipeline Company LLC; Tallgrass Interstate Gas Transmission, LLC; and Rockies Express Pipeline LLC
TAPS	Transmission Access Policy Study Group
TransCanada	TransCanada Corporation
United Airlines Petitioners	United Airlines, Inc.; American Airlines, Inc.; Delta Air Lines, Inc.; Southwest Airlines, Co.; BP West Coast Products LLC; ExxonMobil Oil Corporation; Chevron Products Company; HollyFrontier Refining & Marketing LLC; Valero Marketing and Supply Company; Airlines for America; and the National Propane Gas Association
Williams	Williams Companies, Inc.

165 FERC ¶ 61,115
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. PL19-2-000

Accounting and Ratemaking Treatment of Accumulated Deferred Income Taxes and Treatment Following the Sale or Retirement of an Asset

(Issued November 15, 2018)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Policy Statement.

SUMMARY: In this Policy Statement, the Federal Energy Regulatory Commission (Commission) states its policy regarding the treatment of Accumulated Deferred Income Taxes for both accounting and ratemaking purposes as to Commission-jurisdictional public utilities, natural gas pipelines and oil pipelines, in light of the Tax Cuts and Jobs Act of 2017. In addition, the Commission addresses the accounting and ratemaking treatment of Accumulated Deferred Income Taxes following the sale or retirement of an asset.

EFFECTIVE DATE: This Policy Statement will become effective **[date of publication in the *Federal Register*].**

FOR FURTHER INFORMATION CONTACT:

Sharli Silva (Legal Information)
Office of the General Counsel
888 First Street, NE
Washington, DC 20426
(202) 502-8719
Sharli.Silva@ferc.gov

Bryan Wheeler (Technical Information)
Office of Energy Markets Regulation
Federal Energy Regulatory Commission
888 First Street, NE

Washington, DC 20426
(202) 502-8497
Bryan.Wheeler@ferc.gov

Monil Patel (Technical Information)
Office of Energy Markets Regulation
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(202) 502-8296
Monil.Patel@ferc.gov

Kimberly Horner (Technical Information)
Office of Enforcement
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(202) 502-8623
Kimberly.Horner@ferc.gov

SUPPLEMENTARY INFORMATION:

165 FERC ¶ 61,115
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Neil Chatterjee, Chairman;
Cheryl A. LaFleur and Richard Glick.

Accounting and Ratemaking Treatment of Accumulated Deferred Income Taxes and Treatment Following the Sale or Retirement of an Asset — Docket No. PL19-2-000

POLICY STATEMENT

(Issued November 15, 2018)

1. In this Policy Statement, the Federal Energy Regulatory Commission (Commission) states its policy regarding the treatment of Accumulated Deferred Income Taxes (ADIT) for both accounting and ratemaking purposes as to Commission-jurisdictional public utilities, natural gas pipelines, and oil pipelines, in light of the Tax Cuts and Jobs Act of 2017.[1] The Commission also addresses the accounting and ratemaking treatment of ADIT following the sale or retirement of an asset.

I. Background

A. Tax Cuts and Jobs Act

2. On December 22, 2017, the President signed into law the Tax Cuts and Jobs Act. The Tax Cuts and Jobs Act, among other things, reduced the federal corporate income tax

[1] An Act to provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018, Pub. L. No. 115-97, 131 Stat. 2054 (2017) (Tax Cuts and Jobs Act).

rate from 35 percent to 21 percent, effective January 1, 2018.[2] This means that, beginning January 1, 2018, companies subject to the Commission's jurisdiction will compute income taxes owed to the Internal Revenue Service (IRS) based on a 21 percent tax rate. The tax rate reduction will result in less corporate income tax expense going forward.

3. Importantly, the tax rate reduction will also result in a reduction in ADIT liabilities and ADIT assets on the books of rate-regulated companies. ADIT balances are accumulated on the regulated books and records of such regulated companies based on the requirements of the Uniform System of Accounts (USofA).[3] ADIT arises from timing differences between the method of computing taxable income for reporting to the IRS and the method of computing income for regulatory accounting and ratemaking purposes.[4] As a result of the Tax Cuts and Jobs Act reducing the federal corporate income tax rate from 35 percent to 21 percent, a portion of an ADIT liability that was collected from customers will no longer be due from public utilities, natural gas pipelines and oil pipelines to the IRS and is considered excess ADIT.

---

[2] *Id.* Sec. 13001, 131 Stat. at 2096.

[3] *See* Definition of Accounts 182.3 and Account 254, 18 CFR part 101, *Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act*; *see* Definition of Accounts 182.3 and Account 254, 18 CFR part 201, *Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act; see* General Instructions 1-12, Accounting for Income Taxes, 18 CFR part 352, *Uniform Systems of Accounts Prescribed for Oil Pipeline Companies Subject to the Provisions of the Interstate Commerce Act*.

[4] *See* 18 CFR 35.24(d)(2) (2018).

B. Order No. 144

4. The purpose of tax normalization is to match the tax effects of costs and revenues with the recovery in rates of those same costs and revenues.[5] As noted above, timing differences may exist between the method of computing taxable income for reporting to the IRS and the method of computing income for regulatory accounting and ratemaking purposes. The tax effects of these differences are placed in a deferred tax account to be used in later periods when the differences reverse.[6]

5. The Commission established this policy of tax normalization in Order No. 144 where it required use of "the provision for deferred taxes [(i.e., ADIT)] as a mechanism for setting the tax allowance at the level of current tax cost."[7] In keeping with this normalization policy, and as relevant to the Tax Cuts and Jobs Act's reduction of the federal corporate income tax rate, the Commission in Order No. 144 also required adjustments in the ADIT of public utilities' cost of service when excessive or deficient ADIT has been created as a result of changes in tax rates.[8] Furthermore, the Commission required "a rate applicant to compute the income tax component in its cost of service by making provision for any excess

---

[5] *Tax Normalization for Certain Items Reflecting Timing Differences in the Recognition of Expenses or Revenues for Ratemaking and Income Tax Purposes*, Order No. 144, FERC Stats. & Regs. ¶ 30,254 at 31,522, 31,530 (1981), *order on reh'g*, Order No. 144-A, FERC Stats. & Regs. ¶ 30,340 (1982).

[6] Order No. 144, FERC Stats. & Regs. ¶ 30,254 at 31,554.

[7] *Id.* at 31,530.

[8] *Id.* at 31,519.

or deficiency in its deferred tax reserves resulting . . . from tax rate changes."[9] The Commission required that such provision be consistent with a Commission-approved ratemaking method made specifically applicable to the rate applicant.[10] Where no ratemaking method has been made specifically applicable, the Commission required the rate applicant to advance some method in its next rate case.[11] The Commission stated that it would determine the appropriateness of any proposed method on a case-by-case basis, but as the issue is resolved in a number of cases, a method with wide applicability may be adopted.[12] The Commission codified the requirements of Order No. 144 in its regulations in 18 CFR 35.24.[13]

1. Public Utilities – 18 CFR 35.24

6. Originally promulgated in Order No. 144, the Commission's regulations in 18 CFR 35.24 provide requirements for the proper ratemaking treatment of the tax effects of all

---

[9] Order No. 144, FERC Stats. & Regs. ¶ 30,254 at 31,560. *See also* 18 CFR 35.24(c)(1)(ii); 18 CFR 35.24(c)(2).

[10] Order No. 144, FERC Stats. & Regs. ¶ 30,254 at 31,560. *See also* 18 CFR 35.24(c)(3).

[11] Order No. 144, FERC Stats. & Regs. ¶ 30,254 at 31,560.

[12] *Id*. *See also* 18 CFR 35.24(c)(3).

[13] Originally promulgated as part of Order No. 144, the regulatory text was redesignated as 18 CFR 35.25 in Order No. 144-A. *See* Order No. 144-A, FERC Stats. & Regs. ¶ 30,340 at 30,140. In Order No. 545, the Commission again redesignated the regulatory text to its present designation as 18 CFR 35.24. *See Streamlining Electric Power Regulation,* Order No. 545, FERC Stats. & Regs. ¶ 30,955, at 30,713 (1992) (cross-referenced at 61 FERC ¶ 61,207).

transactions for which there are timing differences.[14] Under this section, a public utility must account for excess or deficient ADIT when computing the income tax component of its cost of service.[15] Additionally, in accounting for this excess or deficient ADIT, a public utility is required to apply the ratemaking method that has been specifically approved by the Commission for that public utility.[16] Where no such ratemaking method exists, a public utility may choose which ratemaking method to apply and the reasonableness of that ratemaking method will be determined on a case-by-case basis by the Commission.[17]

2. <u>Natural Gas Pipelines – 18 CFR 154.305</u>

7. Order No. 144 also promulgated the Commission's regulations regarding tax normalization for natural gas pipelines which were originally located in part 2 of the regulations as section 2.202.[18] Order No. 144-A redesignated the tax normalization regulations for natural gas pipelines by removing them from part 2 of the Commission's regulations and placing them in part 154.[19] Subsequently, Order No. 582 redesignated the regulatory text in that part with respect to natural gas pipelines to its current designation in

---

[14] *See id.*

[15] *See* 18 CFR 35.24(c)(1)(ii), (c)(2).

[16] *See* 18 CFR 35.24(c)(3).

[17] *See id.*

[18] Order No. 144, FERC Stats. & Regs. ¶ 30,254.

[19] Order No. 144-A, FERC Stats. & Regs.¶ 30,340 at 30,140. The Commission deemed part 154 a more appropriate location because tax normalization is required to be used by natural gas pipelines in filing their rate applications and the regulations that govern the filing of such rate applications are located in part 154. *Id.*

section 154.305, and made various revisions in that section.[20] The section requires a natural gas pipeline making a rate filing under the Natural Gas Act to compute the income tax component of its cost of service by using tax normalization for all transactions.[21] More specifically, the section requires natural gas pipelines to reduce rate base by the balances that are properly recordable in USofA Account 281 (Accumulated deferred income taxes-accelerated amortization property), Account 282 (Accumulated deferred income taxes—other property), and Account 283 (Accumulated deferred income taxes—other).[22] Conversely, rate base must be increased by balances that are properly recordable in Account 190 (Accumulated deferred income taxes).[23] The section also requires natural gas pipelines to compute the income tax component in its cost of service by including a provision for amortizing excess or deficiency in deferred taxes. This is done by applying a Commission-approved ratemaking method made specifically applicable to the natural gas pipeline for determining the cost-of-service provision: (1) if the natural gas pipeline has not provided deferred taxes in the same amount that would have accrued had tax normalization always been applied or (2) if, as a result of changes in tax rates, the accumulated provision for

[20] 18 CFR 154.305 (2018). *See* Order No. 582, *Filing and Reporting Requirements for Interstate Natural Gas Company Rate Schedules and Tariffs,* FERC Stats. & Regs. ¶ 31,025 (1995), *order on reh'g,* Order No. 582-A, FERC Stats. & Regs. ¶ 31,043 (1996), *order on clarification*, FERC Stats. & Regs. ¶ 31,037 (1996). The tax normalization regulations were moved from 18 CFR 154.63a to 154.305.

[21] 18 CFR 154.305.

[22] 18 CFR 154.305(c)(1).

[23] *Id.*

deferred taxes becomes deficient in, or in excess of, amounts necessary to meet future tax liabilities.[24] Similar to the tax normalization regulations for public utilities, if the Commission has not approved a specific ratemaking method specifically applicable to the natural gas pipeline, then the natural gas pipeline must use a previously approved ratemaking method.[25] The Commission will determine whether such method is appropriate on a case-by-case basis.[26]

3. Oil Pipelines

8. Unlike the Commission's regulations applicable to public utilities and natural gas pipelines, there is no tax normalization section under the Commission's regulations for oil pipelines. Instead, the Commission's regulations for oil pipelines under the USofA General Instructions, 1-12 *Accounting for Income Taxes*, require that when income tax rates are changed, oil pipelines reduce or increase their ADIT balances immediately by the full amount of the excess or deficient tax reserve.[27] Specifically, section (b) requires oil pipelines to apply the enacted tax rate in determining the amount of deferred taxes and adjust their deferred tax liabilities and assets for the effect of the change in tax law or rates

[24] 18 CFR 154.305(d). Such amounts must be included as an addition or reduction to rate base until the deficiency or excess is fully amortized using the Commission approved ratemaking method. *Id.*

[25] 18 CFR 154.305(d)(3).

[26] *Id.*

[27] 18 CFR part 352, General Instructions 1-12, Accounting for Income Taxes.

in the period that the change is enacted.[28] The section further requires the adjustment to be recorded in the appropriate deferred tax balance sheet accounts based on the nature of the temporary difference and the related classification requirements of the account.[29]

4. Prior Accounting Guidance for Public Utilities and Natural Gas Pipelines

9. In Docket No. AI93-5-000, the Chief Accountant issued accounting guidance on the proper accounting for income taxes.[30] Among other matters, the accounting guidance directed public utilities and natural gas companies to adjust their deferred tax liabilities and assets for the effect of the change in tax law or rates in the period that the change is enacted.[31] The guidance stated that adjustments should be recorded in the appropriate deferred tax balance sheet accounts (Accounts 190, 281, 282 and 283) based on the nature of the temporary difference and the related classification requirements of the accounts.[32] Further, if as a result of action by a regulator, it is probable that the future increase or decrease in taxes payable due to the change in tax law or rates will be recovered from or returned to customers through future rates, an asset or liability should be recognized in

---

[28] *Id.*

[29] *Id.*

[30] *See Accounting for Income Taxes,* Docket No. AI93-5-000, at Item 8 (Apr. 23, 1993).

[31] *Id.*

[32] *Id.*

Account 182.3 (Other Regulatory Assets), or Account 254 (Other Regulatory Liabilities), as appropriate, for that probable future revenue or reduction in future revenue.[33]

C. Notice of Inquiry

10. Following the enactment of the Tax Cuts and Jobs Act, the Commission issued a Notice of Inquiry seeking comments on, among other things, whether, and if so, how, the Commission should address the effects on ADIT of the Tax Cuts and Jobs Act.[34] The Commission noted that the Tax Cuts and Jobs Act's reduction to the federal corporate income tax rate would potentially create excess or deficient ADIT on the books of public utilities.[35] As relevant to the guidance provided in this Policy Statement, the Commission sought comments on the treatment of ADIT for assets sold or retired after December 31, 2017, and the amortization of excess and deficient ADIT.[36]

II. Discussion

11. This Policy Statement states our requirements regarding the treatment of ADIT in light of the tax rate reduction implemented in the Tax Cuts and Jobs Act. Specifically, we provide guidance regarding: (1) the accounts in which public utilities, natural gas pipelines, and oil companies should record the amortization of excess and/or deficient ADIT for

---

[33] *Id.*

[34] *Inquiry Regarding the Effect of the Tax Cuts and Jobs Act on Commission-Jurisdictional Rates*, FERC Stats. & Regs. ¶ 35,582 (2018) (NOI). In this Policy Statement, we refer to the comments filed in response to the NOI. A list of commenters in that proceeding and the abbreviated names used in this Policy Statement appears in Appendix A.

[35] NOI, FERC Stats. & Regs. ¶ 35,582 at P 13.

[36] *Id.* PP 20-22.

accounting purposes and ratemaking purposes and (2) whether, and if so how, such entities should address excess and/or deficient ADIT that is recorded on the books of public utilities, natural gas pipelines, and oil companies after December 31, 2017, as a result of assets being sold or retired for both accounting and ratemaking purposes.

12. First, we clarify that for both accounting purposes and ratemaking purposes, public utilities and natural gas companies should record the amortization of the excess and/or deficient ADIT recorded in Account 254 (Other Regulatory Liabilities) and/or Account 182.3 (Other Regulatory Assets) by recording the offsetting entries to Account 410.1 (Provision for Deferred Income Taxes, Utility Operating Income) or Account 411.1 (Provision for Deferred Income Taxes – Credit, Utility Operating Income), as required by the USofA. We further clarify that for accounting purposes oil pipelines should adjust their ADIT balances to reflect the change in federal income tax rates with offsetting entries to the appropriate income statement account, as required by the USofA. Accordingly, oil pipeline companies will not record excess or deficient ADIT for accounting purposes. As detailed below, we also clarify that oil pipelines should provide additional disclosures in the Notes that accompany their FERC Form No. 6, Annual Report of Oil Pipeline Companies (Form No. 6).

13. Second, for accounting purposes, we reiterate that public utilities and natural gas pipelines must continue to follow the accounting guidance issued by the Chief Accountant in Docket No. AI93-5-000 with respect to changes in tax law or rates. To ensure transparency in the accounting adjustments to the deferred tax accounts, we clarify that

entities should provide additional disclosures in their 2018 FERC annual financial filing within the Notes to the Financial Statements as detailed below.

14. With respect to ratemaking, for a public utility or natural gas pipeline that continues to have an income tax allowance, any excess or deficient ADIT associated with an asset must continue to be amortized in rates even after the sale or retirement of that asset. This excess or deficient ADIT will continue to be refunded to or recovered from ratepayers based on the schedule that was initially established. Similarly, for ratemaking purposes oil pipelines should keep records of excess and deficient ADIT.

A. <u>In Which Accounts Should Companies Record Amortization of Excess and Deficient ADIT.</u>

15. In the NOI, the Commission sought comment on whether a public utility or natural gas pipeline should record the amortization by recording a reduction to the regulatory asset or regulatory liability account and recording an offsetting entry to Account 407.3 (Regulatory Debits) or Account 407.4 (Regulatory Credits).[37] For oil pipelines, the Commission sought comment on whether this information should be recorded in Account 665 (Unusual or Infrequent Items (Debit)) or Account 645 (Unusual or Infrequent Items (Credit)).[38]

---

[37] NOI, FERC Stats. & Regs. ¶ 35,582 at P 22.

[38] *Id.*

1. Comment Summary

16. Ameren takes issue with the premise of the Commission's question that a separate regulatory liability or asset account is necessary to record excess or deficient ADIT, respectively, arguing that the excess or deficient ADIT should remain in the accounts where they were originally recorded.[39] APPA and AMP, along with Indicated Customers, argue that it would be both appropriate and transparent to record the excess ADIT in the same ADIT accounts (*e.g.,* Accounts 190, 282 and 283) where the original entries for the ADIT assets and ADIT liabilities were established, but believe separate regulatory liability and/or asset accounts would also be appropriate.[40]

17. When separate regulatory liability or assets are used, commenters' viewpoints diverge on the appropriate account to record the offsetting entry. Certain commenters agree with the Commission's initial suggestion.[41] PSEG states that Accounts 407.3 and 407.4 correspond to the appropriate balance sheet account where the excess deferred taxes

---

[39] Ameren, Comments to NOI, Docket No. RM18-12-000, at 16 (filed May 21, 2018) (Ameren NOI Comments).

[40] APPA and AMP, Comments to NOI, Docket No. RM18-12-000, at 16 (filed May 22, 2018) (APPA and AMP NOI Comments); Indicated Customers, Comments to NOI, Docket No. RM18-12-000, at 14 (filed May 21, 2018) (Indicated Customers NOI Comments).

[41] Berkshire, Comments to NOI, Docket No. RM18-12-000, at 5-6 (filed May 22, 2018) (Berkshire NOI Comments); Consumer Advocates, Comments to NOI, Docket No. RM18-12-000, at 8-10 (filed May 21, 2018) (Consumer Advocates NOI Comments); DEMEC, Comments to NOI, Docket No. RM18-12-000, at 16 (filed May 21, 2018) (DEMEC NOI Comments); PSEG, Comments to NOI, Docket No. RM18-12-000, at 10-11 (filed May 22, 2018) (PSEG NOI Comments); TransCanada, Comments to NOI, Docket No. RM18-12-000, at 25 (filed May 21, 2018) (TransCanada NOI Comments).

reside.[42] Regarding natural gas pipelines, Berkshire asserts that recording the amounts in Account 407.3 or 407.4 will be easier for FERC Form No. 2 users to understand because it will result in similar treatment to other IRS schedule M items and above the line accounting while avoiding the requirement to spread the total year's amortization over each month using the FASB Interpretation No. 18 method.[43]

18. Other commenters believe that either Accounts 407.3 and 407.4 or 410.1 (Provision for deferred income taxes, utility operating income) and 411.1 (Provision for deferred income taxes) are appropriate. Avangrid asserts that Account 407 is consistent with the fact that the excess deferred tax obligation ceased upon tax reform enactment and that the utilities will prospectively amortize a regulatory deferral, rather than a deferred tax liability; however, use of Account 411 is consistent with USofA requirements.[44] EEI and INGAA state that their members' opinions are split between the two accounting options and request that the Commission recognize that both approaches may be appropriate.[45]

---

[42] PSEG NOI Comments at 10-11.

[43] Berkshire NOI Comments at 5-6.

[44] Avangrid, Comments to NOI, Docket No. RM18-12-000, at 12-13 (May 22, 2018) (Avangrid NOI Comments).

[45] EEI, Comments to NOI, Docket No. RM18-12-000, at 19-20 (filed May 22, 2018) (EEI NOI Comments); INGAA, Comments to NOI, Docket No. RM18-12-000, at 12 (filed June 5, 2018) (INGAA NOI Comments).

19. Many other commenters believe that only Accounts 410.1 and 411.1 are appropriate.[46] New York Transco notes that those accounts were originally used when the regulatory asset or regulatory liability was established.[47]

20. Regarding oil pipelines, AOPL states with respect to regulatory accounting under the USofA, any excess ADIT is eliminated when tax rates change consistent with generally accepted accounting principles, rather than being reduced over time through amortization. AOPL states there is no reason to change either the Commission's accounting rules or current oil pipeline accounting practices; the Commission's ratemaking precedent controls rather than accounting rules for purposes of setting cost-of-service rates.[48]

2. Determination

a. Accounting Guidance

21. We clarify that public utilities and natural gas pipelines should record the amortization of the excess and/or deficient ADIT recorded in Account 254 (Other

[46] Ameren NOI Comments at 16; APPA and AMP NOI Comments at 16; Dominion Energy Gas Pipelines, Comments to NOI, Docket No. RM18-12-000, at 14-15 (filed May 21, 2018) (Dominion Energy Gas Pipelines NOI Comments); Enable Interstate Pipelines, Comments to NOI, Docket No. RM18-12-000, at 39-40 (filed May 21, 2018) (Enable Interstate Pipelines NOI Comments); Indicated Customers, Comments to NOI, Docket No. RM18-12-000, at 10 (filed May 21, 2018) (Indicated Customers NOI Comments); Indicated Local Distribution Companies, Comments to NOI, Docket No. RM18-12-000, at 11 (filed May 22, 2018) (Indicated Local Distribution Companies NOI Comments); New York Transco, Comments to NOI, Docket No. RM18-12-000, at 10 (filed May 22, 2018) (New York Transco NOI Comments).

[47] New York Transco NOI Comments at 10.

[48] AOPL, Comments to NOI, Docket No. RM18-12-000, at 16 (filed May 22, 2018) (AOPL NOI Comments).

Regulatory Assets) and/or Account 182.3 (Other Regulatory Assets) by recording the offsetting entries to Account 410.1 (Provision for Deferred Income Taxes, Utility Operating Income) or Account 411.1 (Provision for Deferred Income Taxes – Credit, Utility Operating Income), as appropriate. As explained below, recording the amortization in Account 410.1 and Account 411.1 is consistent with the instructions for those accounts as detailed in the Commission's regulations and provides more transparency as compared with recording the amounts in Account 407.3 and Account 407.4 because the specific source of the regulatory asset or regulatory liability will be known.

22. The Commission's instructions for Account 182.3 provide in part "[w]hen specific identification of the particular source of a regulatory asset cannot be made . . . account 407.4, regulatory credits, shall be credited."[49] Similarly, the Commission's instructions for Account 254 state in part "[w]hen specific identification of the particular source of the regulatory liability cannot be made . . . account 407.3, regulatory debits, shall be debited."[50]

23. In contrast, Account 410.1 and Account 411.1 are specifically designated for the recordation of ADIT.[51] In this situation where, as a result of a change in tax law or rates,

---

[49] *See* Definition of Account 182.3, 18 CFR part 101, *Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act*; Definition of Account 182.3, 18 CFR part 201, *Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act.*

[50] *See* Definition of Account 254, 18 CFR part 101, *Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act*; Definition of Account 254, 18 CFR part 201, *Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act.*

[51] *See* Definition of Account 410.1 and 411.1, 18 CFR part 101, *Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the*

excess and/or deficient ADIT have been reclassified to Account 254 and/or Account 182.3, in accordance with the Commission's prior guidance,[52] specific identification of the source of the regulatory liability and/or regulatory asset can be made. Accordingly, the Commission's existing regulations support amortizing the excess and/or deficient ADIT recorded in Account 254 and/or Account 182.3 to Account 410.1 or Account 411.1, as appropriate and consistent with the manner such amounts are reflected in rates.

24. With respect to oil pipelines, deferred tax balances should be adjusted for the effect of changes in tax law or rates in the period the change is enacted in accordance with the USofA for oil pipelines.[53] Specifically, upon the enactment of the Tax Cuts and Jobs Act, oil pipelines should have reduced their ADIT balances to reflect the 21 percent federal income tax rate with offsetting entries to the appropriate income statement account.[54] We believe the current guidance set forth in the USofA is appropriate and will not require oil pipelines to account for excess or deficient ADIT or record the amortization of such amounts. However, to ensure transparency with respect to these ADIT adjustments, oil

Federal Power Act; Definition of Account 410.1 and 411.1, 18 CFR part 201, *Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act.*

[52] *See Accounting for Income Taxes,* Docket No. AI93-5-000, at Item 8 (Apr. 23, 1993).

[53] *See* 18 CFR 352, General Instructions 1-12(b), Accounting for Income Taxes. *See also*, 18 CFR 352, Instructions for Balance Sheet Accounts, 19-5 Current Deferred Income Tax Assets, 45 Accumulated Deferred Income Tax Assets, 59 Deferred Income Tax Liabilities, and 64 Accumulated Deferred Income Tax Liabilities.

[54] *Id*.

pipelines should disclose in the Notes to their Form No. 6 financial statements, the amounts of their ADIT adjustments resulting from the change in the federal corporate income tax rate, supported by a schedule that illustrates the calculation of the revised balances. Because the accounting for the excess and/or deficient ADIT may create differences between oil pipelines' accounting and ratemaking, such differences should also be disclosed in the Notes to their Form No. 6 financial statements, Form No. 6 Page 230, Analysis of Federal Income and Other Taxes Deferred, and Page 700, Annual Cost of Service Based Analysis Schedule.

b. Ratemaking Guidance

25. With respect to public utilities, the appropriate ratemaking treatment will be addressed in the Notice of Proposed Rulemaking (NOPR) we are issuing concurrent with this Policy Statement. In the NOPR, we are proposing to require all public utility transmission providers with transmission rates under an Open Access Transmission Tariff (OATT), a transmission owner tariff, or a rate schedule to revise those rates to account for changes caused by the Tax Cuts and Jobs Act. Natural gas pipelines should continue to file for changes in rates consistent with sections 154.305, 154.312, and 154.313 of the Commission's regulations.[55]

26. For oil pipelines, the current regulatory treatment of excess and/or deficient ADIT amounts is to maintain such amounts separately for rate making purposes only and to amortize them by removing the annual amortization amount from the cost of service in the process of determining an income tax allowance. We will continue the practice of

[55] 18 CFR 154.305, 154.312, 154.313 (2018). Section 154.313 should be used if the filing requests a minor rate change.

amortizing and removing the excess and or deficiency by reducing the allowed return before it is grossed up for income taxes.

B. Whether, and if so how, to address excess ADIT that is removed from the books of public utilities, natural gas pipelines, and oil pipelines after December 31, 2017, as a result of assets being sold or retired.

27. In the NOI, the Commission sought comment on whether, and if so how, it should address excess ADIT that is removed from the books of public utilities, natural gas pipelines, and oil pipelines after December 31, 2017, as a result of assets being sold or retired.[56]

1. Comment Summary

28. Both public utility and natural gas pipeline commenters note that, to date and in response to the last time Congress changed the federal corporate income tax rate, the IRS only has issued guidance on the disposition of excess ADIT in the context of extraordinary retirements.[57] They suggest that the Commission defer addressing excess ADIT that is removed from the books as a result of assets being sold or retired unless and until the IRS has had an opportunity to weigh in on this issue.[58]

---

[56] NOI, FERC Stats. & Regs. ¶ 35,582 at P 20.

[57] *See* Treas. Reg. 26 CFR § 1.168(i)-3, Treatment of Excess Deferred Income Tax Reserve Upon Disposition of Deregulated Public Utility Property.

[58] Avangrid NOI Comments at 11; EEI NOI Comments at 19; Ameren NOI Comments at 15; EQT Midstream, Comments to NOI, Docket No. RM18-12-000, at 14 (filed May 21, 2018) (EQT Midstream NOI Comments); Indicated Transmission Owners, Comments to NOI, Docket No. RM18-12-000, at 10 (filed May 22, 2018); Dominion Energy Gas Pipelines NOI Comments at 13.

29. Certain public utilities argue that, for companies that properly reflect Average Rate Assumption or the Reverse South Georgia Method and have formula rates that reflect ADIT balances and adjustments thereto, there is no need for the Commission to address excess ADIT that is removed from the books after December 2017 as a result of assets being sold or retired.[59]

30. Similarly, several natural gas pipelines contend that Commission precedent is clear that when assets are sold or transferred as part of a taxable event, the ADIT balance associated with those assets is extinguished; similarly, deferred liabilities resulting from excess ADIT are also extinguished following the retirement of an asset. These pipelines believe that the Commission has provided no basis for departing from these clear rules.[60] These pipelines note that the Commission has stated that "ADIT balances consist of deferred taxes that are intended to be paid at a future time - when the taxes become due. When a taxable event occurs such as the sale of assets . . . taxes are due and the ADIT balances are reduced to zero;" thus, the "ADIT balances that existed prior to the sale no longer exist and are no longer an offset against rate base."[61] These pipelines state the NOI explained that any ADIT associated with assets that are sold are removed from the regulated

---

[59] Ameren NOI Comments at 14, MISO Transmission Owners, Comments to NOI, Docket No. RM18-12-000, at 14 (filed May 21, 2018).

[60] EQT Midstream NOI Comments at 14; INGAA NOI Comments at 11-12; Tallgrass, Comments to NOI, Docket No. RM18-12-000, at 12-13 (filed May 21, 2018); AOPL NOI Comments at 14-15; Enable Interstate Pipelines, Comments to NOI, Docket No. RM18-12-000, at 40 (filed on May 21, 2018).

[61] *Id.* (citing *Enbridge Pipeline (KPC),* 102 FERC ¶ 61,310, at PP 5, 68 (2003)).

entity's "books because any previously deferred tax effects related to the assets are now triggered as part of the computation of gains or losses associated with the sale (i.e., the deferred taxes are now payable to the IRS)."[62]

31. Eversource and Exelon submit that treatment of ADIT balances is best addressed on a company-specific basis and that companies should be able to either remove the ADIT associated with assets removed from their books or continue to amortize those balances over the remaining amortization period.[63] Indicated Local Distribution Companies suggest that any future sale or retirement event should be decided as part of a pipeline's general rate proceeding.[64]

32. Other commenters urge the Commission to require regulated entities to return any excess ADIT associated with any sold or retired assets. They argue that the Commission should be guided by the principle that all excess ADIT balances were provided by customers and thus customers should be credited with such balances through the combination of a credit to amortization expense and the continued offset to rate base. In support, they assert that when a public utility sells a jurisdictional asset, it will remove from its books the entire ADIT associated with a sold asset, which does not transfer with the asset to the new owner, and retain the entire ADIT for investors. Thus, customers are never credited with the excess

[62] *Id.* (citing NOI, FERC Stats. & Regs. ¶ 35,582 at P 20).

[63] Eversource, Comments to NOI, Docket No. RM18-12-000, at 10 (filed May 22, 2018); Exelon, Comments to NOI, Docket No. RM18-12-000, at 14 (filed May 22, 2018).

[64] Indicated Local Distribution Companies NOI Comments at 9.

or any other part of the ADIT that they have been paying during the useful life of the asset prior to its sale.[65]

33. Indicated Customers note that with regard to the sale of public utility assets for which there is an excess ADIT balance remaining on the books, the 2006 IRS Private Letter Ruling No. PLR-168537-02 prohibits the return to ratepayers of that ADIT and excess ADIT related to the asset that is being sold, because any ADIT and excess ADIT amounts that are on the books for that asset cease to exist as of the date of sale.[66] Notwithstanding, Indicated Customers, and APPA and AMP argue that the impact of not returning both the ADIT and excess ADIT, prior to the sale, and the consequent appropriation of customer-provided capital, should be given consideration in the Commission's evaluation of the application seeking approval of the asset transfer. If the ADIT and excess ADIT are not considered in the transfer transaction, they contend that the selling entity would receive a windfall to the detriment of ratepayers. Further, the acquiring utility could have no offsetting ADIT in its

---

[65] Consumer Advocates NOI Comments at 8; Indicated Customers NOI Comments at 10-11; DEMEC NOI Comments, Kumar Test. at P 14.

[66] I.R.S. P.L.R., 168537-02 at 9 (May 25, 2006) ("Because [t]axpayer has sold the assets that generated the [accumulated deferred investment tax credit] ADITC, the asset for which regulated depreciation expense is computed is no longer available. Consequently, no portion of the related unamortized ADITC remaining at the date of sale may be returned to ratepayers by amortizing those ADITC amounts over the period [t]axpayer recovers stranded costs from its ratepayers or by decreasing the net loss from the sale of the nuclear generating assets by those ADITC amounts. Additionally, the unamortized [accumulated deferred investment tax credit] and [excess deferred federal income taxes] associated with the sold generating assets ceases to exist at the date of sale."). APPA and AMP argue that this Private Letter Ruling can be read to have no bearing on the flowback of unprotected ADIT balances. APPA and AMP NOI Comments at n. 8.

rate base related to the purchased assets, thereby causing an increase in rates to customers, in addition to the customers' loss of capital advanced to the selling utility.[67]

34. Commenters that believe that the Commission should require ADIT balances be returned to the customers offer several suggestions. APPA and AMP suggest that in the case of a sale or early retirement of public utility assets, the flowback should occur immediately in the formula rate update after the event; otherwise, the flowback should be in the form of a lump-sum payment or credit.[68] Indicated Customers suggest that the Commission should consider deploying remedies it has used in proceedings under FPA section 203, such as establishing an open season for customers to terminate their contracts, a commitment by applicants to protect customers from any adverse rate impacts, rate moratorium or rate reduction.[69] Natural Gas Indicated Shippers suggest that the excess ADIT associated with sold or retired assets should be amortized and returned to the customers in the same manner a pipeline proposes to return excess ADIT due to tax cost changes.[70]

---

[67] Indicated Customers NOI Comments at 10-11; APPA and AMP NOI Comments at 13-14.

[68] APPA and AMP NOI Comments at 13-14.

[69] Indicated Customers NOI Comments at 11-12 (citing *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, FERC Stats. & Regs. ¶ 31,044 (1996), *order on reconsideration*, 79 FERC ¶ 61,321 (1997)).

[70] Tallgrass Pipelines, Comments to NOI, Docket No. RM18-12-000, at 18 (filed May 22, 2018).

2. Determination

a. Accounting Guidance

35. As discussed above, in 1993, the Chief Accountant issued guidance on how entities must account for the effect of a change in tax law or rates by adjusting its deferred tax liabilities and assets.[71] This guidance remains unchanged, and requires an entity to adjust its deferred tax liabilities and assets for the effect of the change in tax law or rates in the period that the change is enacted.[72] If as a result of action by a regulator, it is probable that the future increase or decrease in taxes payable due to a change in tax law or rates will be recovered from or returned to customers through future rates, an asset or liability shall be recognized in Account 182.3 (Other Regulatory Assets) for deficient ADIT, or Account 254 (Other Regulatory Liabilities) for excess ADIT, as appropriate.[73] Because these deficient ADIT and excess ADIT balances can no longer be characterized as deferred tax amounts to be settled with the IRS, the sale or retirement of any assets as of January 1, 2018 would not automatically reverse these balances as tax timing differences.

36. Accordingly, for public utilities and natural gas pipelines, the excess and/or deficient ADIT recorded in Account 254 and/or Account 182.3 should continue to be recorded in those accounts and amortized to Accounts 410.1 and/or Account 411.1, if those balances are

---

[71] *See Accounting for Income Taxes,* Docket No. AI93-5-000, at Item 8 (Apr. 23, 1993).

[72] *Id.*

[73] *Id.*

still deemed to be either refundable to or recoverable from ratepayers. If the rate treatment of those balances is instead disallowed, then those amounts shall be written off to Account 421 (Miscellaneous Non-Operating Income) or Account 426.5 (Other Deductions), as appropriate, in the year of the disallowance.[74]

37. We clarify that, for public utilities and natural gas pipelines, the balances of excess and deficient ADIT recorded in Account 254 and Account 182.3, respectively, continue to exist as regulatory liabilities and assets after an asset sale, in cases for which the excess and deficient ADIT do not transfer to the purchaser of the plant asset. Similarly, we clarify that public utilities and natural gas companies should continue to account for excess and deficient ADIT related to retirements as regulatory liabilities and assets.

38. We acknowledge that numerous current and deferred tax accounts as well as other accounts may be affected by reversals of ADIT account balances recorded on the books of public utilities and natural gas companies subject to the Commission's jurisdiction. Thus, in order to provide transparency regarding the accounting and rate treatment of amounts removed from the ADIT accounts, we clarify that public utilities and natural gas pipelines should disclose in their FERC annual financial filings within the Notes to the Financial Statements: (1) the FERC accounts affected; (2) how any ADIT accounts were re-measured in the determination of the excess or deficient ADIT amounts in Accounts 182.3

[74] *See* Definitions of Account 182.3 and Account 254, 18 CFR part 101, *Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act*; Definitions of Account 182.3 and Account 254, 18 CFR part 201, *Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act.*

and 254; (3) the related amounts associated with the reversal and elimination of ADIT balances in those accounts; (4) the amount of excess and deficient ADIT that is protected and unprotected; (5) the accounts to which the excess or deficient ADIT will be amortized; and (6) the amortization period of the excess and deficient ADIT to be returned or recovered through rates for both protected and unprotected ADIT.[75] Disclosures should also summarize the manner by which excess and deficient will be included in rates by rate jurisdiction.

39. As for oil pipelines, as discussed above, ADIT balances will be reduced immediately by the full amount of the excess or deficient tax reserve in line with the USofA for oil pipelines outlined in General Instruction 1-12.[76]

b. <u>Ratemaking Guidance</u>

40. The Commission has previously found that the sale or retirement of an asset with an ADIT balance is usually deemed a taxable event under IRS rules, and, as such, the ADIT balance is extinguished as the deferred taxes then become payable to the appropriate government authorities, and there is no longer an ADIT balance to "return" to customers.[77]

---

[75] Public utilities should include this information in FERC Form No. 1 or 1-A and natural gas pipelines should include this information in FERC Form No. 2 or 2-A.

[76] General Instructions 1-12, *Accounting for Income Taxes*, 18 CFR part 352.

[77] The Commission has found that master limited partnerships that were no longer entitled to an income tax allowance were not required to return any remaining ADIT balances. *Inquiry Regarding the Commission's Policy for Recovery of Income Tax Costs,* 162 FERC ¶ 61,227, *order on reh'g*, 164 FERC ¶ 61,030 (2018) (Revised Income Tax Policy Statement Order on Rehearing). However, as relevant here, the Commission found that "[t]here is a critical distinction between adjustments to amortize excess or deficient ADIT to be included in future rates to account for changes in income tax rates, as opposed

However, we believe that excess or deficient ADIT associated with post-December 31, 2017, asset dispositions and retirements should be treated differently for ratemaking purposes. For these assets, there are two associated balances: (1) the ADIT balance based on the 21 percent tax rate that will be owed to the IRS and (2) deficient ADIT or excess ADIT balances resulting from the reduced tax liability that will not be payable to the IRS upon the sale or retirement of the asset. While the ADIT balance that needs to be settled with the IRS would be extinguished following a sale, the deficient ADIT or excess ADIT balances is more reflective of a regulatory liability or asset, and no longer reflects deferred taxes that are still to be settled with the IRS and need not be extinguished.

41. Additionally, we note that the rationale for continuing to amortize deficient ADIT or excess ADIT balances in rates upon sales or retirements of assets is substantively similar to the rationale for amortizing excess ADIT in rates for assets that have not been sold or retired. The difference is that for a sale or retirement, ADIT based on a 21 percent tax rate will be settled with the IRS immediately, while for an asset that is not sold or retired, the ADIT will be settled with the IRS over the remaining life of the asset as it depreciates. In other words, the difference between the ADIT for assets that are sold or retired and ADIT for assets that are not sold or retired is the timing of when companies will settle the 21

---

to a complete elimination of the income tax allowance. When income tax rates are merely reduced and an income tax allowance remains in *future* cost of service, it is appropriate to credit any excess in ADIT in the *future* cost of service." Revised Income Tax Policy Statement Order on Rehearing, 164 FERC ¶ 61,030 at P 20. Thus, in the case of retired or sold assets of regulated entities that continue to have an income tax allowance (and in the case of all regulated entities with excess and deficient ADIT), it is appropriate to credit any excess in ADIT in the future cost of service.

percent of ADIT with the IRS. In both scenarios, there is excess ADIT based on the 14 percent previously collected from the customers that will no longer be payable to the IRS.

42. While some commenters suggest that continuing to amortize excess or deficient ADIT following a sale or retirement would constitute a normalization violation based on certain IRS private letter rulings, the Commission notes that the IRS established a rulemaking proceeding and reversed its positions made in the PLR referenced by the commenters.[78] Current IRS regulations speak specifically to the normalization requirements for sales and retirements as a result of the Tax Reform Act of 1986.[79] These regulations permit the amortization of protected excess and/or deficient ADIT even in the event that the underlying asset associated with the ADIT has been sold or retired.[80] That is, the selling jurisdictional entity can continue to amortize excess ADIT in rates after the sale without violating the IRS' normalization requirements. The only limitation imposed by the IRS is

[78] *See Application of Normalization Accounting Rules to Balances of Excess Deferred Income Taxes and Accumulated Deferred Investment Tax Credits of Public Utilities Whose Assets Cease To Be Public Utility Property*, 73 FR 14,934 (Mar. 20, 2008); *Application of Normalization Accounting Rules to Balances of Excess Deferred Income Taxes and Accumulated Deferred Investment Tax Credits of Public Utilities Whose Assets Cease to Be Public Utility Property*, 70 FR 75,762 (Dec. 21, 2005) (notice of proposed rulemaking, notice of public hearing, and withdrawal of previous proposed regulations).

[79] 26 CFR 1.168(i)-3 (2018). This section of the IRS code does not apply to ordinary retirements within the meaning of 26 CFR 1.167(a) –11(d)(3)(ii) of the internal revenue regulations, and such retirements are excluded from this policy statement.

[80] *Id.*

that the timing of the amortization must be similar to protected excess and/or deficient ADIT for which the underlying asset has not been sold or retired.[81]

43. Consistent with the above discussion, oil pipelines should continue maintaining excess and/or deficient ADIT within the appropriate ADIT accounts for ratemaking purposes. When jurisdictional assets are retired or sold the oil pipeline should continue to amortize any excess and/or deficient amounts associated with those assets as part of the process of determining an income tax allowance within the rate making process, or seek prior Commission approval to do otherwise.

C. Conclusion

44. We adopt the policies set forth herein regarding the treatment of ADIT for public utilities, natural gas pipelines and oil pipelines. Above, we state our policy regarding the treatment of ADIT for both accounting and ratemaking purposes as to Commission-jurisdictional public utilities, natural gas pipelines and oil pipelines, in light of the Tax Cuts and Jobs Act of 2017 and also address the accounting and ratemaking treatment of ADIT following the sale or retirement of an asset. We expect such regulated entities to follow these policies absent prior Commission approval to use a different treatment. We further note that if a regulated entity determines that its unique circumstances merit a different treatment of ADIT, such an entity is free to request such treatment at any time.

---

[81] *Id.*

III. <u>Document Availability</u>

48. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

49. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

50. User assistance is available for eLibrary and the FERC's website during normal business hours from FERC Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

IV. Effective Date

51. This Policy Statement will become effective **[date of publication in the *Federal Register*]**.

By the Commission. Commissioner McIntyre is not voting on this order.

(S E A L)

Nathaniel J. Davis, Sr.,

Deputy Secretary.

Note: Appendix A will not be published in the Federal Register.

Appendix A – List of Commenters to NOI

Short Name	Commenter
AEP	American Electric Power Service Corporation
Ameren	Ameren Services Company on behalf of Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois, and Ameren Transmission Company of Illinois
AOPL	Association of Oil Pipe Lines
APGA	American Public Gas Association
APPA and AMP	American Public Power Association and American Municipal Power, Inc.
Avangrid	Avangrid Networks, Inc.
Berkshire	Berkshire Hathaway Energy Pipeline Group
Boardwalk	Boardwalk Pipeline Partners LP
CAPP	Canadian Association of Petroleum Producers
Consumer Advocates	Office of the Attorney General of the Commonwealth of Massachusetts; the Ohio Consumers' Counsel; the Maryland Office of People's Counsel; the Nevada Bureau of Consumer Protection; the Delaware Division of the Public Advocate; the Pennsylvania Office of Consumer Advocate; the Citizens Utility Board of Wisconsin; and the Indiana Office of Utility Consumer Counselor
DEMEC	Delaware Municipal Electric Corporation, Inc.
Dominion Energy Gas Pipelines	Dominion Energy Transmission, Inc.; Dominion Energy Carolina Gas Transmission, LLC; Dominion Energy Quester Pipeline, LLC; Dominion Energy Overthrust Pipeline, LLC; and Questar Southern Trails Pipeline Company

EEI	Edison Electric Institute
Enable Interstate Pipelines	Enable Mississippi River Transmission, LLC and Enable Gas Transmission, LLC
Enbridge and Spectra	Enbridge Energy Partners, L.P. and Spectra Energy Partners, LP
EQT Midstream	EQT Midstream Partners, LP
Eversource	Eversource Energy Service Company
Exelon	Exelon Corporation
Indicated Customers	Central Electric Power Cooperative, Inc., North Carolina Electric Membership Corporation, Southern Maryland Electric Cooperative, Inc., and the New Jersey Division of Rate Counsel
Indicated Local Distribution Companies	Atmos Energy Corporation; the City of Charlottesville, Virginia; the City of Richmond, Virginia; the Easton Utilities Commission; Exelon Corporation; and Washington Gas Light Company
Indicated Transmission Owners	American Electric Power Service Corporation; Dominion Energy Services, Inc., on behalf of Virginia Electric and Power Company d/b/a Dominion Energy Virginia; Duquesne Light Company; Exelon Corporation; FirstEnergy Service Company, on behalf of American Transmission Systems, Incorporated; Jersey Central Power & Light Company; Mid-Atlantic Interstate Transmission, LLC; West Penn Power Company; The Potomac Edison Company; Monongahela Power Company; and PPL Electric Utilities Corp.
INGAA	Interstate Natural Gas Association of America
ITC Great Plains	ITC Great Plains, LLC
Kentucky Municipals	Frankfort Plant Board of Frankfort, Kentucky; Barbourville Utility Commission of the City of Barbourville, City; Utilities Commission of the City of Corbin; and the Cities of Bardwell, Berea, Falmouth, Madisonville, and Providence, Kentucky

Kinder Morgan Entities	Natural Gas Pipeline Company of America LLC; Tennessee Gas Pipeline Company, L.L.C.; Southern Natural Gas Company, L.L.C.; Colorado Interstate Gas Company, L.L.C.; Wyoming Interstate Company, L.L.C.; El Paso Natural Gas Company, L.L.C.; Mojave Pipeline Company, L.L.C.; Bear Creek Storage Company, L.L.C.; Cheyenne Plains Gas Pipeline Company, L.L.C.; Elba Express Company, L.L.C.; Kinder Morgan Louisiana Pipeline LLC; Southern LNG Company, L.L.C.; and TransColorado Gas Transmission Company LLC
Kinder Morgan Subsidiaries	SFPP, L.P.; Calnev Pipe Line, LLC; and Kinder Morgan Cochin, LLC
MISO Transmission Owners	Ameren Services Company, as agent for Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois and Ameren Transmission Company of Illinois; American Transmission Company LLC; Central Minnesota Municipal Power Agency; City Water, Light & Power (Springfield, IL); Cleco Power LLC; Cooperative Energy; Dairyland Power Cooperative; Duke Energy Business Services, LLC for Duke Energy Indiana, LLC; East Texas Electric Cooperative; Entergy Arkansas, Inc.; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy New Orleans, LLC; Entergy Texas, Inc.; Great River Energy; Indiana Municipal Power Agency; Indianapolis Power & Light Company; International Transmission Company d/b/a ITC*Transmission*; ITC Midwest LLC; Lafayette Utilities System; Michigan Electric Transmission Company, LLC; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Missouri River Energy Services; Montana-Dakota Utilities Co.; Northern Indiana Public Service Company LLC; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Prairie Power Inc.; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); Southern Minnesota Municipal Power Agency; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc.

National Grid	National Grid USA
Natural Gas Indicated Shippers	Aera Energy, LLC; Anadarko Energy Services Company; Apache Corporation; BP Energy Company; ConocoPhillips Company; Hess Corporation; Occidental Energy Marketing, Inc.; Petrohawk Energy Corporation; and XTO Energy, Inc.
New York Transco	New York Transco LLC
Oklahoma Attorney General	Mike Hunter, Oklahoma Attorney General
PJM	PJM Interconnection, L.L.C.
Plains	Plains Pipeline, L.P.
Process Gas and American Forest and Paper	Process Gas Consumers Group and American Forest and Paper Association
PSEG	Public Service Electric and Gas Company
Tallgrass Pipelines	Trailblazer Pipeline Company LLC; Tallgrass Interstate Gas Transmission, LLC; and Rockies Express Pipeline LLC
TAPS	Transmission Access Policy Study Group
TransCanada	TransCanada Corporation
United Airlines Petitioners	United Airlines, Inc.; American Airlines, Inc.; Delta Air Lines, Inc.; Southwest Airlines, Co.; BP West Coast Products LLC; ExxonMobil Oil Corporation; Chevron Products Company; HollyFrontier Refining & Marketing LLC; Valero Marketing and Supply Company; Airlines for America; and the National Propane Gas Association
Williams	Williams Companies, Inc.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON. D C 20426

In Reply Refer To:
AI935000

April 23, 1993

TO ALL JURISDICTIONAL PUBLIC UTILITIES, LICENCES,
AND NATURAL GAS COMPANIES

SUBJECT: ACCOUNTING FOR INCOME TAXES

INTRODUCTION

In February 1992, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes (SFAS 109). This Statement was the culmination of a process which the FASB began in 1982 to reexamine the accounting standards for income taxes. SFAS 109 superseded Accounting Principles Board

Opinion No. 11, Accounting for Income Taxes (APB 11).

Under SFAS 109, a current or deferred tax liability or asset is recognized for the current or deferred tax consequences of all events that have been recognized in the financial statements or tax returns, measured on the basis of enacted tax law. Under APB 11, deferred tax consequences were recognized based on the differences between the periods in which transactions affect taxable income and the periods in which they enter into the determination of pretax accounting income. The change affects significantly the measurement and recognition of current and deferred income taxes reported in general purpose financial statements.

Public utilities, licensees, and natural gas companies are required to implement the provisions of SFAS 109 in general purpose financial statements issued to the public no later than the first quarter of 1993. The Statement however encouraged earlier application.

The FERC's Uniform Systems of Accounts generally provide that an entity follow comprehensive interperiod income tax allocation except that an entity is not required to adopt comprehensive interperiod income tax allocation until the deferred income taxes are included as an expense in its rate levels by regulatory authorities.

Since the issuance of Order No. 144 in 1981, the FERC's regulations have required companies to determine the income tax allowance included in jurisdictional rate levels on a fully normalized basis. Also, Order No. 144 requires an entity to compute the income tax component in its cost of service by making provision for any excess or deficiency in deferred taxes under the following circumstances: (1) if the entity has not provided deferred taxes in the same amount that would have accrued had tax normalization been applied for tax effects of timing difference transactions originating at any time prior to the test period; or (2) if, as a result of changes in tax rates, the accumulated provision for deferred taxes becomes deficient in or in excess of amounts necessary to meet future tax liabilities as determined by application of the current tax rate to all timing difference transactions originating in the test period and prior to the test period. Therefore, the FERC's accounting and rate regulations, when read together, already require use of a liability method somewhat similar to SFAS 109 for the jurisdictional portion of an entity's business.

The primary conceptual difference between SFAS 109 and the FERC's method relates to how regulatory assets and liabilities are recognized. Under the FERC approach, regulatory assets and liabilities are effectively netted against the deferred tax asset and liability accounts or, in some cases, not reported until related revenues are recognized. Under SFAS 109 all tax related regulatory assets and liabilities are shown broad. Certain other differences between the FERC's Uniform Systems of Accounts and SFAS 109 are discussed in the guidance that follows.

It is axiomatic that accounting statements issued by the FASB for use in general purpose financial statements of business entities should not, in itself, have an economic rate effect on a regulated entity or its customers. SFAS 109, in the main, requires costbased regulated entities to account for and report deferred tax assets and liabilities separately from related regulatory assets and liabilities. In general, such increases in the level of detail for an entity's assets and liabilities enhance disclosure, making financial information more useful to its users. The enhanced disclosure required by SFAS 109 may also prove useful for regulatory purposes. Moreover, adoption of SFAS 109 for FERC accounting and reporting purposes would result in financial information reported to the FERC and the public using the same accounting standard an objective having considerable merit in its own right.

Therefore, public utilities, licensees, and natural gas companies shall adopt SFAS 109 for financial accounting and reporting to FERC. In order to insure that the FERC continues to have the financial information it needs for regulatory purposes however, entities shall conform their accounting and reporting to the guidance provided in this letter. Neither SFAS 109 nor the guidance contained in this letter for implementing the standard for FERC financial accounting and reporting purposes relieves entities from the requirements of Section

154.63a, Tax normalization for interstate pipelines, or Section 35.24, Tax normalization for public utilities, of the Commission's regulations.

The Commission delegated authority to the Chief Accountant under 18 C.F.R. 375.303 to issue interpretations of the Uniform System of Accounts for public utilities, licensees and natural gas companies and sign correspondence on behalf of the Commission relating to Annual Report Nos. 1, lF, 2, and 2F. The guidance provided herein constitutes final agency action pursuant to this authority. Within 30 days of the date of this letter, interested parties may file a request for rehearing by the Commission under 18 C.F.R. § 385.713.

1. EARLY ADOPTION

Question: SFAS 109 is effective for fiscal years beginning
after December 15, 1992, but the FASB encourages
earlier application. May an entity implement SFAS
109 for FERC accounting and reporting requirements
prior to January 1, 1993?

Response: An entity implementing SFAS 109 in its general purpose financial statements prior to the Statement's required effective date, may also adopt the Statement for FERC accounting and reporting purposes. An entity however shall not implement SFAS 109 for FERC accounting and reporting purposes before it implements the Statement in its general purpose financial statements. Entities shall implement SFAS 109 for FERC accounting and reporting purposes no later than fiscal years beginning after December 15, 1992.

2. METHOD OF ADOPTION

Question: In the first year applied, SFAS 109 permits an entity to either (1) include the cumulative effect of the accounting change in the determination of current year net income, as provided for in APB Opinion No. 20, Accounting Changes; or (2) restate financial statements for prior periods to conform to the provisions of the Statement. Are both of these procedures acceptable to the FERC?

Response: No. In reporting to the FERC, the effect of initially applying this statement shall be reported as the cumulative effect of a change in accounting principle in accordance with the provisions of APB 20. An entity will not be permitted to restate prior years financial statements.

3. FERC APPROVAL TO ADJUST THE DEFERRED TAX ACCOUNTS

Question: The instructions to the Uniform Systems of Accounts presently restrict the use of the deferred tax balance sheet accounts to the purposes set forth in the text of the accounts unless prior Commission approval is obtained. Do the adjustments to the deferred tax accounts for the implementation of SFAS 109 fall within this restriction?

Response: Yes. This letter however, will constitute the requisite authority for making adjustments to the deferred tax accounts when the application of SFAS 109 does not affect net income (i.e. the deferred tax adjustments are accompanied by the recordation of equal regulatory assets or liabilities). Entities shall request and obtain specific FERC approval for all other adjustments to the deferred tax accounts, including those related to nonjurisdictional activity. The filing shall include a complete explanation of and justification for an entity's proposed accounting.

4. REPORTING ANY NET INCOME EFFECT

Question: If the initial implementation of SFAS 109 affects net income and an entity obtains FERC approval to adjust its deferred tax accounts, where should the income effect be reported in FERC financial reports (i.e. FERC Form Nos. 1, 1-F, 2 and 2-A etc.)?

Response: The FERC report forms do not currently have a line for reporting the cumulative effect of a change in accounting principle.

Therefore, the effect on net income shall be reported on the income statement on the lines designated for extraordinary income or deductions, as appropriate, in FERC financial reports. To identify that the effects on net income resulting from the initial adoption of SFAS 109 are not an "extraordinary item" as that term is defined in the Uniform Systems of Accounts, entities shall also disclose in a footnote to the financial statements the full particulars of any amounts reports as the cumulative effect of a change in accounting principle.

5. DISCONTINUANCE OF NET-OF-TAX ACCOUNTING

Question: SFAS 109 prohibits net-of-tax accounting and reporting in general purpose financial statements. May entities continue to account and report to FERC on a net-of-tax basis?

Response: No. The present instructions to the Uniform Systems of Accounts require entities to record and report the deferred tax consequences of transactions, events, and circumstances in the appropriate deferred tax accounts. While the FERC has always preferred gross-of-tax financial accounting and reporting, it permitted an exception to this general requirement where a net-of-tax allowance for funds used during construction (AFUDC) rate was prescribed by a regulatory body in setting an entity's rate levels. The FERC granted this exception to avoid the burden of maintaining duplicate records for utility plant on a net-of-tax basis for one jurisdiction and a gross-of-tax basis for another.

Because SFAS 109 prohibits netoftax accounting and reporting in general purpose financial statements, the reasons for permitting the exception to the general requirement are no longer relevant. Therefore, entities shall discontinue the use of netoftax AFUDC rates.

6.EQUITY AFUDC

Question: SFAS 109 considers the equity component of AFUDC a temporary difference for which deferred income taxes must be provided. How should an entity record the deferred tax liability for the equity component of AFUDC and the related regulatory asset in its accounts?

Response: An entity shall record the deferred tax liability for the equity component of AFUDC in Account 282, Accumulated Deferred Income Taxes Other Property, and any corresponding regulatory asset in Account 182.3, Other Regulatory Assets. The regulatory asset is itself a temporary difference for which deferred incomes taxes shall be recognized and recorded in Account 283, Accumulated Deferred Income Taxes Other. This accounting shall be followed for the adjustments required upon initial application of the statement and for all amounts of equity AFUDC capitalized in subsequent periods.

7. ADJUSTING NETOFTAX COMPONENTS OF UTILITY PLANT

Question: Upon initial application of SFAS 109, an entity must adjust any netoftax components of construction workinprogress and plant in service. How should an entity account for these adjustments?

Response: Entities that previously accounted for certain components of plant cost on a netoftax basis, primarily the borrowed funds component of AFUDC, have effectively recorded the deferred income tax effects of those components directly in the plant accounts. The deferred income taxes were computed using the income tax rates in effect when the items were capitalized.

For constructionworkinprogress, an entity shall transfer the deferred income taxes actually included therein to Account 282, Accumulated Deferred Income Taxes Other Property. If the amount transferred to Account 282 is greater or less than the amount needed to meet the future tax liability related to those items based on current tax rates, additional adjustments to the deferred tax liability shall be made consistent with SFAS 109. If as a result of action by a regulator it is probable that such excess or deficiency will be returned to or recovered from customers in rates, an asset or liability shall be recognized for that probable future revenue or reduction in future revenue in Accounts 182.3, Other Regulatory Assets, or 254, Other Regulatory Liabilities, respectively. That asset or liability is also a temporary difference for which a deferred tax asset or liability shall be recognized in Account 190, Accumulated Deferred Income Taxes, or Account 283, Accumulated Deferred Income Taxes Other, as appropriate.

Similar accounting is to be followed for plantin-service items when the required information is available. However, in order to properly adjust the plantinservice account an entity will need to determine the specific amounts of borrowed funds and equity AFUDC capitalized in prior periods, the extent to which those amounts and other netoftax components have been depreciated, the specific property units to which the amounts have been assigned and the extent to which property retirements affect the accounts in which the income tax effects now reside. In virtually all instances that information will simply not be available or will be too costly to develop. In that situation, an entity shall not adjust the plantinservice accounts based on estimates or presumed relationships. Instead, an alternate method shall be used to determine the necessary adjustments.

Under the alternate method, any difference between the reported amount and the tax basis of plant is a temporary difference for which a deferred tax liability shall be recorded in Account 282. If as a result of action by a regulator, it is probable that amounts required for settlement of that deferred tax liability will be recovered from customers through future rates, a regulatory asset equal to that probable future revenue should be recorded in Account 182.3. That asset is also a temporary difference for which a deferred tax liability shall be recognized in Account 283, Accumulated Deferred Income Taxes Other.

8. CHANGES IN TAX LAW OR RATES

Question: How should an entity record the effect of a change in tax law or rates that occurs after the year of initial implementation of SFAS 109?

Response: The entity shall adjust its deferred tax liabilities and assets for the effect of the change in tax law or rates in the period that the change is enacted. The adjustment shall be recorded in the proper deferred tax balance sheet accounts (Accounts 190, 281, 282 and 283) based on the nature of the temporary difference and the related classification requirements of the accounts. If as a result of action by a regulator, it is probable that the future increase or decrease in taxes payable due to the change in tax law or rates will be recovered from or returned to customers through future rates, an asset or liability shall be recognized in Account 182.3, Other Regulatory Assets, or Account 254, Other Regulatory Liabilities, as appropriate, for that probable future revenue or reduction in future revenue. That asset or liability is also a temporary difference for which a deferred tax asset or liability shall be recognized in Account 190, Accumulated Deferred Income Taxes or Account 283, Accumulated Deferred Income Taxes Other, as appropriate.

9. FLOWTHROUGH ITEMS

Question: An entity adopting SFAS 109 previously flowed through the tax benefits of certain temporary differences in rates when the differences originated. How should the Company recognize the deferred income taxes attributable to these temporary differences in its accounts?

Response: Deferred income taxes on all temporary differences, including differences where the related income tax effects have been or are presently flowed through in rates, should be recorded in Accounts 190, 281, 282 and 283 based on the nature of the temporary difference and the classification requirements of those accounts. If as a result of action by a regulator, it is probable that the future increase or decrease in taxes payable due to flow through ratemaking practices will be recovered from or returned to customers through future rates, an asset or liability shall be recognized in Account 182.3, Other Regulatory Assets, or Account 254, Other Regulatory Liabilities, as appropriate, for that probable future revenue or reduction in future revenue. That asset or liability is also a temporary difference for which a deferred tax asset or liability shall be recognized in Account 190, Accumulated Deferred Income Taxes or

Account 283, Accumulated Deferred Income Taxes Other, as appropriate.

10.NOL AND TAX CREDIT CARRYFORWARDS

Question: How should an entity account for the income tax effect of a net operating loss (NOL) carryforward or a tax credit carryforward?

Response: An entity shall record the income tax effects of a NOL carryforward and a tax credit carryforward in a separate subaccount of Account 190, Accumulated Deferred Income Taxes Debit. In the event that it is more likely than not (a likelihood of more than 50 percent) that some portion of its deferred tax assets will not be realized, an entity hall record a valuation allowance in a separate subaccount of Account 190. The entity shall disclose full particulars as to the nature and amount of each type of operating loss and tax credit carryforward in the notes to the financial statements.

11. ALTERNATIVE MINIMUM TAX CREDIT CARRYFORWARD

Question: How should an entity record an alternative minimum tax credit carryforward?

Response: SFAS 109 requires a deferred tax liability or asset to be recognized for the estimated future tax effects attributable to temporary differences and carryforwards. Under SFAS 109, the AMT is viewed as a tax credit carryforward. Therefore, an entity shall record an alternative minimum tax credit carryforward in a separate subaccount of Account 190, Accumulated Deferred Income Taxes.

12. REGULATORY ASSETS AND LIABILITIES

Question: Where an entity recognizes regulatory assets or liabilities in connection with a change in its deferred tax assets and liabilities, should an entity record the change in the required deferred income tax balances in the appropriate income tax expense accounts and separately recognize the creation of regulatory assets and liabilities in a different income statement account? If so, which income statement account should be used to record the creation of regulatory assets and liabilities?

Response: The FERC recently considered the proper accounting for regulatory assets and liabilities in a rulemaking proceeding, Docket No. RM921000. Under the final rule issued in that proceeding (Commission Order No. 552 issued March 31,1993), an entity is not required to use income statement accounts to recognize regulatory assets and liabilities related to changes in deferred tax assets or liabilities when an equal and corresponding deferred tax asset or liability is recorded.

13. COSTOFSERVICE TARIFFS

Question: An entity has a costofservice tariff under which monthly billings are based on recorded amounts under FERC's Uniform Systems of Accounts. Under the tariff, only the amounts recorded in certain specified accounts affect the monthly billings. For example, the tariff may specify that Account 282 must be included in the determination of rate base but is silent with respect to Account 254. If implementing SFAS 109 for FERC accounting and reporting results in a reduction in the balance in Account 282 but a corresponding and equal increase in Account 254 (to recognize a regulatory liability) may an entity adjust its monthly billings to give proper effect to the revised accounting for income taxes?

Response: Adoption of SFAS 109 for FERC accounting and reporting purposes should not affect the measurement of cost included in an entity's billing determinations. If an entity's billing determinations would be affected by adoption of SFAS 109, because of the provisions of its tariffs, the entity shall make a filing with the proper rate regulatory authorities prior to implementing the change for tariff billing purposes.

14. INVESTMENT TAX CREDITS

Question: Some entities accounted for investment tax credits using the deferral method. SFAS 109 views deferred investment tax credits as a temporary difference (i.e. as a reduction in the book basis of the property) for which deferred income taxes are required. How should the deferred income taxes be recorded?

Response: The deferred income taxes attributable to deferred investment tax credits shall be recorded in a separate subaccount of Account 190, Accumulated Deferred Income Taxes. If as a result of action by a regulator it is probable that the reduction in future taxes payable due to the tax deductibility of the higher tax basis of the property will be returned to customers in rates, a regulatory liability shall be recorded for the amount by which future rates will be reduced. The regulatory liability shall be recorded in Account 254, Other Regulatory Liabilities. The regulatory liability is itself a temporary difference for which deferred incomes taxes shall be recognized. Those deferred income taxes shall also be recorded in Account 190.

15. FINANCIAL STATEMENT DISCLOSURE

Question: SFAS 109 requires certain financial statement disclosures concerning income taxes. Should entities disclose the same information in financial statements filed with FERC?

Response: Yes. In addition to the disclosure requirements specified elsewhere in this letter, entities shall follow the disclosure requirements of SFAS 109 in any financial statements filed with the FERC. The required information shall be shown in the Notes To Financial Statements.

16. CLASSIFICATION OF CURRENT PORTION OF DEFERRED INCOME TAXES

Question: SFAS 109 requires entities that prepare classified statements of financial position to separate deferred tax liabilities and assets into current and noncurrent amounts. Should entities reclassify the current portion of deferred tax liabilities or assets to current accounts, such as Account 174, Miscellaneous Current and Accrued Assets, or Account 242, Miscellaneous

Current and Accrued Liabilities, for FERC accounting and financial reporting purposes?

Response: No. All deferred tax liabilities and assets shallbe recorded in Accounts 190, 281, 282, or 283, asappropriate, and the current portion of thoseamounts shall not be reclassified to otheraccounts for FERC reporting purposes.

17. CONSOLIDATED INCOME TAXES

Question: Prior to SFAS 96, the FASB (or its predecessor) had not issued any specific pronouncements related to how an entity that joins in the filing of a consolidated income tax return should determine income tax expense in its separately reported financial statements.

Footnote 12 of SFAS 96 provided that the consolidated amount is the amount of current and deferred taxes reported in the consolidated financial statements for the group, or the amount that would be reported if such financial statements were prepared. Under SFAS 96, the sum of the amounts allocated to members of the group (net of consolidation eliminations) would equal the consolidated amount.

SFAS 109 modified the requirements set forth in SFAS 96. SFAS 109 does not require one particular method to allocate the consolidated income tax liability between members of a group. Instead, SFAS 109 permits a number of methods, including methods in which the sum of the amounts allocated to individual members of the group may not equal the consolidated amount. SFAS 109 specifically states that a method that allocates current and deferred taxes to members of the group as if each member were a separate taxpayer (separate return method) is consistent with the statement's criteria.

Will the FERC permit an entity to use a separate return method for FERC financial accounting and reporting?

Response: No. The FERC has issued several decisions rejecting the use of the separate return method for determining income tax expense when an entity files as part of a consolidated group. Instead, the FERC relies on the standalone method of allocating income taxes between members of a consolidated group.

Under the standalone method the consolidated tax expense is allocated to individual members through recognition of the benefits/burdens contributed by each member of the consolidated group to the consolidated return. Under the standalone method, the sum of amounts allocated to individual members equal the consolidated amount.

Russell E. Faudree Jr.
Chief Accountant

165 FERC ¶ 61,117
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35.24

[Docket No. RM19-5-000]

Public Utility Transmission Rate Changes to Address Accumulated Deferred Income Taxes

(Issued November 15, 2018)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is proposing to require all public utility transmission providers with transmission rates under an Open Access Transmission Tariff (OATT), a transmission owner tariff, or a rate schedule to revise those rates to account for changes caused by the Tax Cuts and Jobs Act of 2017 (Tax Cuts and Jobs Act). Specifically, for transmission formula rates, the Commission is proposing to require that public utilities deduct excess accumulated deferred income taxes (ADIT) from or add deficient ADIT to their rate bases and adjust their income tax allowances by amortized excess or deficient ADIT. The Commission is also proposing to require all public utilities with transmission formula rates to incorporate a new permanent worksheet into their transmission formula rates that will annually track ADIT information. Additionally, the Commission is proposing to require all public utilities with transmission stated rates to determine the amount of excess and deferred income tax

caused by the Tax Cuts and Jobs Act's reduction to the federal corporate income tax rate and return or recover this amount to or from customers.

DATES: Comments are due **[INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**

ADDRESSES: Comments, identified by docket number, may be filed electronically at http://www.ferc.gov in acceptable native applications and print-to-PDF, but not in scanned or picture format. For those unable to file electronically, comments may be filed by mail or hand-delivery to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, N.E., Washington, D.C. 20426. The Comment Procedures Section of this document contains more detailed filing procedures.

FOR FURTHER INFORMATION CONTACT:

Noah Lichtenstein (Technical Information)
Office of Energy Market Regulation
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(202) 502-8696
noah.lichtenstein@ferc.gov

Joshua Walters (Legal Information)
Office of the General Counsel
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(202) 502-6098
joshua.walters@ferc.gov

SUPPLEMENTARY INFORMATION:

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Public Utility Transmission Rate Changes to Address Accumulated Deferred Income Taxes — Docket No. RM19-5-000

NOTICE OF PROPOSED RULEMAKING

TABLE OF CONTENTS

Paragraph Numbers

165 FERC ¶ 61,117
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Public Utility Transmission Rate Changes to Address Accumulated Deferred Income Taxes — Docket No. RM19-5-000

NOTICE OF PROPOSED RULEMAKING

(Issued November 15, 2018)

1. In this Notice of Proposed Rulemaking (Proposed Rule), we are proposing to require all public utility transmission providers with transmission rates under an Open Access Transmission Tariff (OATT), a transmission owner tariff, or a rate schedule to revise those rates to account for changes caused by the Tax Cuts and Jobs Act of 2017 (Tax Cuts and Jobs Act).[1] These proposed reforms are designed to address the effects of the Tax Cuts and Jobs Act on the Accumulated Deferred Income Taxes (ADIT) reflected in all transmission rates under an OATT, a transmission owner tariff, or a rate schedule of public utility transmission providers. The proposed reforms are intended to ensure that

[1] An Act to provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018, Pub. L. No. 115-97, 131 Stat. 2054 (2017) (Tax Cuts and Jobs Act). In proposing this new requirement, the Commission relies on existing Commission regulations relating to tax normalization for public utilities as those regulations apply to public utilities with transmission formula or stated rates. *See* 18 CFR 35.24. In this Proposed Rule, the Commission does not propose any generic reforms as to non-public utilities or the non-transmission rates of public utilities. While any conclusions that the Commission makes in this proceeding may be relevant to such rates, they will be addressed on a case-by-case basis. Furthermore, to the extent any entity believes that the Tax Cuts and Jobs Act renders any existing Commission-jurisdictional rate unjust and unreasonable, that entity may submit a complaint to the Commission.

ratepayers receive the benefits of the Tax Cuts and Jobs Act, and that the public utility transmission formula and stated rates are just and reasonable and not unduly discriminatory or preferential following the enactment of the Tax Cuts and Jobs Act. The proposed reforms are also intended to ensure that transmission formula and stated rates meet the Commission's tax normalization requirements such that the income tax component of those rates is calculated as though the taxable income were recognized in the same period and amount by the Internal Revenue Service (IRS) and the Commission.[2]

2. The proposed reforms generally fall into three categories and apply to public utilities with transmission formula rates and stated rates in different ways. First, we propose to require all public utilities with transmission formula rates to include a mechanism in their formula rates to deduct any excess ADIT from or add any deficient ADIT to their rate bases. This will ensure that rate base continues to be treated in a manner similar to that prior to the Tax Cuts and Jobs Act (i.e., that rate base neutrality is preserved). As for public utilities with transmission stated rates, we do not propose any new requirements regarding rate base neutrality.

3. Second, we propose to require all public utilities with transmission formula rates to include a mechanism in their formula rates that decreases or increases their income tax

[2] In this Proposed Rule, the Commission refers to comments filed in response to the Notice of Inquiry issued March 15, 2018. *Inquiry Regarding the Effect of the Tax Cuts and Jobs Act on Commission-Jurisdictional Rates*, FERC Stats. & Regs. ¶ 35,582 (2018) (NOI). A list of commenters in that proceeding and the abbreviated names used in this Proposed Rule appears in Appendix A. Any comments to this Proposed Rule should be filed in this proceeding, Docket No. RM19-5-000.

allowances by any amortized excess or deficient ADIT, respectively. This reform will help to ensure that public utilities with transmission formula rates return excess ADIT to or recover deficient ADIT from ratepayers. As a result, ratepayers who contributed to excess ADIT balances will receive the benefit of the Tax Cuts and Jobs Act.

4. With regard to public utility transmission providers with stated rates, we are proposing to require these entities to determine the excess and deficient ADIT caused by the Tax Cuts and Jobs Act based on the ADIT amounts approved in their last rate case and then to return this amount to or recover this amount from customers. This reform is intended to increase the likelihood that those customers who contributed to the related ADIT accounts receive the benefits of the Tax Cuts and Jobs Act.

5. Third, we propose to require all public utilities with transmission formula rates to incorporate a new permanent worksheet into their transmission formula rate that will annually track information related to excess or deficient ADIT. We believe that this reform will increase the transparency surrounding the adjustment of rate bases and income tax allowances to account for excess or deficient ADIT by public utilities with transmission formula rates. We do not propose any additional worksheets for public utilities with transmission stated rates because we believe that existing regulations require sufficient transparency.

6. We seek comments on these proposed reforms and areas for further comment within 30 days after publication of this Proposed Rule in the *Federal Register*.

I. Background

A. Tax Cuts and Jobs Act

7. On December 22, 2017, the President signed into law the Tax Cuts and Jobs Act. The Tax Cuts and Jobs Act, among other things, reduced the federal corporate income tax rate from 35 percent to 21 percent, effective January 1, 2018. This means that, beginning January 1, 2018, companies subject to the Commission's jurisdiction will compute income taxes owed to the IRS based on a 21 percent tax rate. The tax rate reduction will result in less corporate income tax expense going forward.[3]

8. Importantly, the tax rate reduction will also result in a reduction in ADIT liabilities and ADIT assets on the books of rate-regulated companies. ADIT balances are accumulated on the regulated books and records of public utilities based on the requirements of the Uniform System of Accounts. ADIT arises from timing differences between the method of computing taxable income for reporting to the IRS and the method of computing income for regulatory accounting and ratemaking purposes.[4] As a result of the Tax Cuts and Jobs Act reducing the federal corporate income tax rate from 35 percent to 21 percent, a portion of an ADIT liability that was collected from customers will no longer be due from public utilities to the IRS and is considered excess ADIT, which must be returned to customers in a cost of service ratemaking context. Additionally, for public utilities that have an ADIT asset, the Tax Cuts and Jobs Act will

[3] *See* Tax Cuts and Jobs Act, Sec. 13001, 131 Stat. at 2096.

[4] *See* 18 CFR 35.24(d)(2).

result in a reduction to that ADIT asset, and public utilities may seek to reflect in rates a portion of such reductions. Public utilities are required to adjust their ADIT assets and ADIT liabilities for the effect of the change in tax rates in the period that the change is enacted.[5]

B. Overview of Public Utility Transmission Rates

9. The Commission is responsible for ensuring that the rates, terms and conditions of service for wholesale sales and transmission of electric energy in interstate commerce are just, reasonable, and not unduly discriminatory or preferential. With respect to the transmission of electric energy in interstate commerce, most jurisdictional entities are subject to cost of service regulation. Cost of service regulation seeks to allow public utilities the opportunity to (1) recover operating costs, including income taxes, (2) recover the cost of capital investments, and (3) earn a just and reasonable return on investments.[6] Public utilities have calculated their cost of service-based transmission rates predominately by using formula rates or stated rates. These rates are contained in numerous agreements, including a public utility's OATT, a regional transmission operator's or independent system operator's OATT, coordination agreements, and wholesale distribution agreements. In this Proposed Rule, we focus on all public utilities

[5] *See* 18 CFR 35.24 and 18 CFR 154.305; *see also Regulations Implementing Tax Normalization for Certain Items Reflecting Timing Differences in the Recognition of Expenses or Revenues for Ratemaking and Income Tax Purposes*, Order No. 144, FERC Stats. & Regs. ¶ 30,254 (1981), *order on reh'g*, Order No. 144-A, FERC Stats. & Regs. ¶ 30,340 (1982).

[6] *See Pub. Sys. v. FERC*, 709 F.2d 73, 75 (D.C. Cir. 1983).

with transmission formula or stated rates that are contained in an OATT, a transmission owner tariff, or a rate schedule.

10. When a public utility uses stated rates, if the public utility seeks to change its rate, it files a rate case at the Commission to establish the cost of service revenue requirement, allocate costs to various customer groups, and calculate rates. As an alternative, the Commission permits public utilities to establish rates through formulas, in which the Commission accepts the public utility's cost of service calculation methodologies and input sources and allows the public utility to update those inputs every year.

11. Public utilities must seek changes to their transmission stated rates or formula rates through filings with the Commission under section 205 of the Federal Power Act (FPA),[7] while the Commission and third parties can challenge a rate in a proceeding initiated under section 206 of the FPA.[8]

C. <u>Order No. 144 and 18 CFR 35.24</u>

12. The purpose of tax normalization is to match the tax effects of costs and revenues with the recovery in rates of those same costs and revenues.[9] As noted above, timing differences may exist between the method of computing taxable income for reporting to the IRS and the method of computing income for regulatory accounting and ratemaking

[7] *See* 16 U.S.C. 824d.

[8] *See* 16 U.S.C. 824e(a).

[9] Order No. 144, FERC Stats. & Regs. ¶ 30,254 at 31,522, 31,530.

purposes. The tax effects of these differences are placed in a deferred tax account to be used in later periods when the differences reverse.[10]

13. The Commission established this policy of tax normalization in Order No. 144 where it required use of "the provision for deferred taxes [(i.e., ADIT)] as a mechanism for setting the tax allowance at the level of current tax cost."[11] In keeping with this normalization policy, and as relevant to the Tax Cuts and Jobs Act's reduction of the federal corporate income tax rate, the Commission in Order No. 144 also required adjustments in the ADIT of public utilities' cost of service when excessive or deficient ADIT has been created as a result of changes in tax rates.[12] Furthermore, the Commission required "a rate applicant to compute the income tax component in its cost of service by making provision for any excess or deficiency in its deferred tax reserves resulting . . . from tax rate changes."[13] The Commission required that such provision be consistent with a Commission-approved ratemaking method made specifically applicable to the rate applicant.[14] Where no ratemaking method has been made specifically

[10] *Id.* at 31,554.

[11] *Id.* at 31,530.

[12] *Id.* at 31,519.

[13] Order No. 144, FERC Stats. & Regs. ¶ 30,254 at 31,560. *See also* 18 CFR 35.24(c)(1)(ii); 18 CFR 35.24(c)(2).

[14] Order No. 144, FERC Stats. & Regs. ¶ 30,254 at 31,560. *See also* 18 CFR 35.24(c)(3).

applicable, the Commission required the rate applicant to advance some method in its next rate case.[15] The Commission stated that it would determine the appropriateness of any proposed method on a case-by-case basis, but as the issue is resolved in a number of cases, a method with wide applicability may be adopted.[16] The Commission codified the requirements of Order No. 144 in its regulations in 18 CFR 35.24.[17]

D. Notice of Inquiry

14. Following the enactment of the Tax Cuts and Jobs Act, the Commission issued the NOI seeking comments on, among other things, whether, and if so, how, the Commission should address the effects of the Tax Cuts and Jobs Act on ADIT.[18] The Commission noted that the Tax Cuts and Jobs Act's reduction to the federal corporate income tax rate would potentially create excess or deficient ADIT on the books of public utilities.[19] As relevant to the reforms proposed in this Proposed Rule, the Commission sought comments on the preservation of rate base neutrality and how public utilities should make

[15] Order No. 144, FERC Stats. & Regs. ¶ 30,254 at 31,560.

[16] *Id*. *See also* 18 CFR 35.24(c)(3).

[17] Originally promulgated as part of Order 144, the regulatory text was redesignated as 18 CFR 35.25 in Order No. 144-A. *See* Order No. 144-A, FERC Stats. & Regs. ¶ 30,340 at 30,140. In Order No. 545, the Commission again redesignated the regulatory text to its present designation as 18 CFR 35.24. *See Streamlining Electric Power Regulation,* Order No. 545, FERC Stats. & Regs. ¶ 30,955, at 30,713 (1992) (cross-referenced at 61 FERC ¶ 61,207).

[18] NOI, FERC Stats. & Regs. ¶ 35,582.

[19] *Id.* P 13.

related adjustments to their rate bases for excess and deficient ADIT.[20] The Commission also sought comment on how public utilities should adjust their income allowances to return or recover excess or deficient ADIT, respectively,[21] as well as the method used to return or recover excess or deficient protected and unprotected ADIT.[22] Finally, the Commission sought comment on whether it should require public utilities to provide to the Commission, on a one-time basis, additional information to show the computation of excess or deficient ADIT and the corresponding return of excess ADIT to customers or recovery of deficient ADIT from customers. If so, the Commission also sought comments on what types of information public utilities should provide.[23]

II. <u>Discussion</u>

15. Since the issuance of Order No. 144, the landscape of public utility transmission rates has changed dramatically; that is, the vast majority of public utilities now use formula rates rather than stated rates. As described above, unlike stated rates, which are updated only through a rate case initiated by a FPA section 205 application by the public

[20] *Id.* PP 14-15.

[21] *Id.* P 21.

[22] *Id.* PP 17, 19. In the NOI, the Commission referred to "plant-based" and "non-plant based" ADIT. We agree with commenters' recommendation to follow the IRS terminology of "protected" and "unprotected" ADIT instead of "plant-based" and "non-plant based" presented in the NOI. The IRS terms for "protected" and "unprotected" are directly associated with the IRS' normalization protections to ensure a tax payer maintains the benefit of accelerated depreciation over the life of the related asset. Accordingly, we have changed the terms used in this Proposed Rule to better mirror IRS terminology.

[23] *Id.* P 23.

utility or an FPA section 206 action by the Commission or a complaining third party, inputs to formula rates are updated annually to derive a charge assessed to customers. Thus, a rate case no longer remains the appropriate vehicle for formula rates to reflect excess or deficient ADIT in a public utility's cost of transmission service, as contemplated by Order No. 144. The public utility's transmission formula rate should include provisions that accurately reflect excess or deficient ADIT in a public utility's cost of transmission service during the annual updates of the rest of the revenue requirement.

16. Following the NOI, we have determined that this near-industry-wide transition from stated to formula rates has caused a gap in the transmission formula rates of public utilities such that many, if not most, of those rates do not contain provisions to fully reflect any excess or deficient ADIT following a change in tax rates, as required by Order No. 144 and the Commission's regulations in 18 CFR 35.24. Two components are necessary to maintain an accurate cost of service following a change in income tax rates, such as that caused by the Tax Cuts and Jobs Act: (1) preservation of rate base neutrality through the removal of excess ADIT from or addition of deficient ADIT to rate base; and (2) the return of excess ADIT to or recovery of deficient ADIT from ratepayers.[24]

17. A review of public utility transmission formula rates suggests that only some transmission formula rates contain the first component, while even fewer contain the

[24] *Id.* P 13. While the Tax Cuts and Jobs Act decreased the federal corporate income tax rate, the reforms proposed in this Proposed Rule are also meant to ensure that transmission formula rates reflect the effects of tax increases, as well.

second. Consequently, as discussed in greater detail below, we propose to require public utilities with transmission formula rates to revise those rates to include these two components. Additionally, to provide greater transparency, we propose to require all public utilities with transmission formula rates to incorporate a new permanent worksheet into their transmission formula rates that will annually track ADIT information related to these two components.

18. Regarding public utilities with transmission stated rates, we propose maintaining Order No. 144's requirement that such public utilities reflect any adjustments made to their ADIT balances as a result of the Tax Cuts and Jobs Act (and any future tax changes) in their next rate case. However, to increase the likelihood that those customers who contributed to the related ADIT accounts receive the benefit of the Tax Cuts and Jobs Act, we propose to require public utilities with transmission stated rates to (1) determine any excess or deficient ADIT caused by the Tax Cuts and Jobs Act and (2) return or recover this amount to or from customers. We believe that the Commission's existing regulations already require all of the information necessary to support the changes proposed herein to reflect the effects of the Tax Cuts and Jobs Act on a transmission stated rate. Therefore, we propose not to require any additional worksheets.

19. The Commission generally does not permit single-issue ratemaking. However, similar to the Commission's actions following the Tax Cuts and Jobs Act,[25] given the

[25] *See AEP Appalachian Transmission Company, Inc.*, 162 FERC ¶ 61,225 (2018); *Alcoa Power Generating Inc.—Long Sault Division*, 162 FERC ¶ 61,224 (2018).

limited scope of the reforms proposed here, we propose that compliance filings made in response to this Proposed Rule's final requirements may be considered on a single-issue basis.[26]

A. <u>Ensuring Rate Base Neutrality</u>

1. <u>NOI</u>

20. In the NOI, the Commission sought comment on how to ensure that rate base continues to be treated in a manner similar to that prior to the Tax Cuts and Jobs Act (i.e., how to preserve rate base neutrality), until excess and deficient ADIT have been fully returned or recovered in a just and reasonable manner. The Commission also sought comment on whether, and if so how, public utilities should make adjustments to rate base to reflect excess and deficient ADIT. The Commission asked that commenters address both formula rates and stated rates.[27]

2. <u>Comments</u>

21. Numerous public utilities and other commenters assert that, in order to preserve rate base neutrality, unamortized balances of excess ADIT must continue to be treated as an offset to (i.e., a deduction from) rate base until those balances are flowed back in their

[26] *See generally Indicated RTO Transmission Owners*, 161 FERC ¶ 61,018, at PP 13-14 (2017); s*ee also Rates Changes Relating to the Federal Corporate Income Tax Rate for Public Utilities*, Order No. 475, FERC Stats. & Regs. ¶ 30,752, *order on reh'g*, 41 FERC ¶ 61,029 (1987) (allowing public utilities to use a voluntary, abbreviated rate filing procedure to reduce their rates to reflect a reduction in the federal corporate income tax rate on a single-issue basis).

[27] NOI, FERC Stats. & Regs. ¶ 35,582 at PP 14-15.

entirety to customers.[28] These commenters generally note that, following the passage of the Tax Cuts and Jobs Act, public utilities transferred excess ADIT to Account 254 (Other Regulatory Liabilities) or Account 182.3 (Other Regulatory Assets), as appropriate.[29] Accordingly, these commenters state that, just as the ADIT balances were deducted from or added to rate base, as appropriate, the corresponding amounts recorded in Accounts 254 and 182.3 should be deducted from or added to rate base. While generally agreeing that rate base adjustments are necessary, several commenters assert that there is no "one-size fits all" solution.[30]

[28] APPA and AMP, Comments to NOI, Docket No. RM18-12-000, at 4-7 (filed on May 22, 2018) (APPA and AMP NOI Comments); Avangrid, Comments to NOI, Docket No. RM18-12-000, at 5 (May 22, 2018) (Avangrid NOI Comments); Consumer Advocates, Comments to NOI, Docket No. RM18-12-000, at 4-5 (filed May 21, 2018) (Consumer Advocates NOI Comments); DEMEC, Comments to NOI, Docket No. RM18-12-000, at 8 (filed May 21, 2018) (DEMEC NOI Comments); Indicated Customers, Comments to NOI, Docket No. RM18-12-000, at 3-6 (filed May 21, 2018) (Indicated Customers NOI Comments); National Grid, Comments to NOI, Docket No. RM18-12-000, at 6-7 (filed May 21, 2018) (National Grid NOI Comments); New York Transco, Comments to NOI, Docket No. RM18-12-000, at 5 (filed May 22, 2018) (New York Transco NOI Comments); Oklahoma Attorney General, Comments to NOI, Docket No. RM18-12-000, at 4 (filed May 22, 2018) (Oklahoma Attorney General NOI Comments); PSEG, Comments to NOI, Docket No. RM18-12-000, at 4 (filed May 22, 2018) (PSEG NOI Comments).

[29] Avangrid NOI Comments at 5; EEI, Comments to NOI, Docket No. RM18-12-000, at 10 (filed May 22, 2018) (EEI NOI Comments).

[30] Kentucky Municipals, Comments to NOI, Docket No. RM18-12-000, at 3-5 (filed May 21, 2018) (Kentucky Municipals NOI Comments); Exelon, Comments to NOI, Docket No. RM18-12-000, at 11-12 (filed May 22, 2018) (Exelon NOI Comments); TAPS, Comments to NOI, Docket No. RM18-12-000, at 3 (filed May 21, 2018) (TAPS NOI Comments); Indicated Transmission Owners, Comments to NOI, Docket No. RM18-12-000, at 7 (filed May 21, 2018) (Indicated Transmission Owners NOI Comments) (("[t]here may be no uniform way to achieve the Commission's rate base

22. Regarding public utilities with formula rates, several commenters support the addition of a line item to formula rates for rate base adjustments reflecting excess or deficient ADIT recorded in Accounts 254 and 182.3.[31] Many of these commenters suggest that the Commission permit public utilities to make single-issue FPA section 205 filings to make the appropriate changes to their formula rates.[32] EEI suggests that the Commission should permit utilities with formula rates requiring adjustments to address these during their next true-up annual informational filing.[33]

23. Alternatively, APPA and AMP, and Indicated Customers suggest that any excess or deficient ADIT resulting from the implementation of the Tax Cuts and Jobs Act be recorded to the same ADIT accounts (e.g., Accounts 190, 281, 282, and 283) where the original entries for the regulatory assets and regulatory liabilities were established.[34] APPA and AMP state that by keeping the excess or deficient ADIT in sub-accounts

neutrality objective given differences between companies in accounting methods and rate structures.") (citation omitted)).

[31] Oklahoma Attorney General NOI Comments at 4-5; PSEG NOI Comments at 4; Avangrid NOI Comments at 5-9; Eversource, Comments to NOI, Docket No. RM18-12-000, at 4 (filed May 22, 2018) (Eversource NOI Comments); National Grid NOI Comments at 7-8; TAPS NOI Comments at 4.

[32] Eversource NOI Comments at 4-5; Indicated Transmission Owners NOI Comments at 6; PSEG NOI Comments at 4-5; National Grid NOI Comments at 7-8.

[33] EEI NOI Comments at 11.

[34] APPA and AMP NOI Comments at 7-8; Indicated Customers NOI Comments at 6-7.

within the original ADIT accounts, it will be more transparent and easier to track as the balances are flowed back.[35] As another alternative, the Oklahoma Attorney General asserts that the Commission should consider requiring that the line item currently used to offset rate base with ADIT include both ADIT balances in traditional ADIT-related accounts and those excess ADIT balances in other accounts identified by the Commission.[36]

24. Other commenters note that such a line item adjustment may not be necessary in all cases.[37] Specifically, these commenters assert that certain formula rates (e.g., certain MISO Attachment O, AEP, Exelon, and Eversource formula rates) already provide for the inclusion of excess ADIT in rate base and that the balances in Accounts 254 and 182.3 will naturally flow into rate base without any modification.[38]

25. Regarding public utilities with stated rates, commenters generally agree that adjustments are not necessary to preserve rate base neutrality with respect to stated

[35] APPA and AMP NOI Comments at 7-8.

[36] Oklahoma Attorney General NOI Comments at 4-5.

[37] Ameren, Comments to NOI, Docket No. RM18-12-000, at 7-8 (filed May 21, 2018) (Ameren NOI Comments); MISO Transmission Owners, Comments to NOI, Docket No. RM18-12-000, at 7 (filed May 21, 2018) (MISO Transmission Owners NOI Comments); EEI NOI Comments at 11; Exelon NOI Comments at 11-12.

[38] AEP, Comments to NOI, Docket No. RM18-12-000, at 3-4 (filed May 22, 2018) (AEP NOI Comments); Ameren NOI Comments at 7-8; MISO Transmission Owners NOI Comments at 7; Eversource NOI Comments at 3-4; Exelon NOI Comments at 11-12.

rates.[39] National Grid and Avangrid state that, under cost-of-service, both ADIT balances and regulatory liability balances should be deducted from rate base in calculating the stated rate.[40] Avangrid asserts that rate base neutrality issues are not raised with transmission stated rates because these rates assume the same amount of ADIT deduction to rate base without regard to how the companies adjusted their books and records.[41]

3. Proposed Requirements

a. Formula Rates

26. We propose to require all public utilities with transmission formula rates to include a mechanism in their formula rates which deducts any excess ADIT from or adds any deficient ADIT to their rate bases under 18 CFR 35.24. As described above, the Commission's regulations in 18 CFR 35.24 require public utilities to reflect any excess or deficient ADIT as a result of any changes in tax rates in their next rate case. As a result of the Tax Cuts and Jobs Act's reduction of the federal corporate income tax from 35 percent to 21 percent, public utilities have collected excess funds for their ADIT liabilities and have not collected sufficient funds for any ADIT assets. To preserve rate base neutrality by accurately matching the tax allowance with the current tax cost as required by Commission regulations, public utilities with transmission formula rates must

[39] National Grid NOI Comments at 7-8; Avangrid NOI Comments at 5-6; EEI NOI Comments at 11.

[40] National Grid NOI Comments at 7-8; Avangrid NOI Comments at 5-6.

[41] Avangrid NOI Comments at 5-6.

include provisions in their formula rates to adjust their ADIT for excess or deficient ADIT.[42] We believe our proposal will ensure that public utilities with transmission formula rates will adjust their ADIT for any excess or deficient ADIT caused by the Tax Cuts and Jobs Act or any future changes to tax rates which may give rise to excess or deficient ADIT.

27. While we are proposing to require public utilities with transmission formula rates to include a mechanism to adjust rate base for any excess or deficient ADIT, we are not proposing to prescribe a specific adjustment mechanism which applies to all public utilities with transmission formula rates. We agree with commenters to the NOI that prescribing a one-size-fits-all approach, such as adding a line item, is not appropriate and that the Commission should instead allow public utilities to propose any necessary changes to their formula rates on an individual basis. Recent filings and comments submitted in the NOI suggest that multiple approaches to modify rate base may be just and reasonable. For example, as noted by MISO Transmission Owners,[43] the Commission accepted proposals by ITC Companies and Ameren in which those companies did not revise their formula rates to modify their adjustments to rate base by adding a new line item for rate base.[44] Instead, those companies demonstrated that, while

[42] Order No. 144, FERC Stats. & Regs. ¶ 30,254 at 31,530, 31,519.

[43] MISO Transmission Owners NOI Comments at 7.

[44] *Midcontinent Indep. Sys. Operator, Inc.*, 153 FERC ¶ 61,374 (2015); *Midcontinent Indep. Sys. Operator, Inc.*, 163 FERC ¶ 61,163 (2018).

not visible in their formula rates, their adjustments to rate base were modified by any excess or deficient ADIT prior to their input to the formula rates. Accordingly, we also propose that public utilities with transmission formula rates may demonstrate that their formula rates already meet the proposed ADIT adjustment requirements described in this Proposed Rule.

28. We are not persuaded by commenters to the NOI who suggest that excess or deficient ADIT amounts should be recorded to the same ADIT accounts where the original entries for the regulatory assets and regulatory liabilities were established. The Commission previously issued guidance on this topic, finding that public utilities are required to record a regulatory asset (Account 182.3) associated with deficient ADIT or regulatory liability (Account 254) associated with excess ADIT.[45] As a result, we do not propose any changes to that specific accounting guidance.

b. <u>Stated Rates</u>

29. We do not propose any new requirements regarding rate base neutrality for public utilities with transmission stated rates. As noted by commenters to the NOI, stated rates are calculated based in large part on company data submitted, and projections made, at the time of the last rate case. Thus, while ADIT balances may have changed as a result of the Tax Cuts and Jobs Act, so too will many other aspects of the cost of service and calculations that underlie the stated rate, making it difficult to re-evaluate ADIT and its

[45] *See* Accounting for Income Taxes, Docket No. AI93-5-000, at 8 (1993).

effect on rate base following a change in tax rates without fully evaluating a public utility's entire cost of service and rates.[46] We believe that the revisions we are proposing below, related to the return or recovery of excess or deficient ADIT, will adequately address the effects of the Tax Cuts and Jobs Act on ADIT and will avoid such complications. Therefore, we do not propose to require adjustments to the rate bases of public utilities with transmission stated rates prior to their next rate case on a generic basis.

B. <u>Return or Recovery of Excess or Deficient ADIT</u>

1. <u>NOI</u>

30. In the NOI, the Commission asked commenters to address how public utilities with stated or formula rates should adjust their income tax allowance such that the allowance would be decreased or increased by the amortization of excess or deficient ADIT, respectively.[47] Additionally, the Commission asked commenters how the Average Rate Assumption Method, and alternatively, the Reverse South Georgia Method or South Georgia Method, as appropriate, will be implemented in the amortization of protected excess or deficient ADIT and how quickly to amortize unprotected excess or deficient ADIT.[48]

[46] The Commission previously acknowledged this difficulty in Order No. 475. Order No. 475, FERC Stats. & Regs. ¶ 30,752 at 30,736.

[47] NOI, FERC Stats. & Regs. ¶ 35,582 at P 21.

[48] *Id.* PP 17, 19. Under the South Georgia method, a calculation is taken of the difference between the amount actually in the deferred account and the amount that would have been in the account had normalization continuously been followed. Any

2. Comments

31. Commenters generally support adjusting public utilities' income tax allowances by the amortization of excess or deficient ADIT. Many commenters suggest adding a line item or several line items to public utility transmission formula rates to make this adjustment,[49] with some transmission owners noting that they have already submitted or now propose to submit such revisions.[50] MISO Transmission Owners note that the Commission accepted such a proposal by ITC Great Plains.[51] National Grid suggests that adjustments to income tax allowances could also be made through the weighted cost of capital.[52]

deficiency is collected from ratepayers (i.e., South Georgia Method), and any excess is returned to ratepayers (i.e., Reverse South Georgia Method), over the remaining depreciable life of the plant that caused the difference. *Memphis Light, Gas and Water Div. v. FERC*, 707 F.2d 565, 569 (D.C. Cir. 1983).

[49] Ameren NOI Comments at 15-16; Avangrid NOI Comments at 11-12; MISO Transmission Owners NOI Comments at 14-17; National Grid NOI Comments at 15; New York Transco NOI Comments at 10; Oklahoma Attorney General NOI Comments at 6; PSEG NOI Comments at 10.

[50] Ameren NOI Comments at 15-16; Avangrid NOI Comments at 11-12; MISO Transmission Owners NOI Comments at 16-17; New York Transco NOI Comments at 10.

[51] MISO Transmission Owners NOI Comments at 15 (citing *Midcontinent Indep. Sys. Operator, Inc.*, 153 FERC ¶ 61,374). *See also Midcontinent Indep. Sys. Operator, Inc.*, 163 FERC ¶ 61,163.

[52] National Grid NOI Comments at 15.

32. Commenters also support revisions to transmission stated rates to reflect income tax allowance adjustments for the amortization of excess or deficient ADIT.[53] TAPS states that, to address these adjustments, it supports an approach similar to utility-specific investigations the Commission opened with respect to the change in the federal corporate income tax rate.[54] However, TAPS expresses concern that stated rate customers will find it challenging to verify their utilities' calculation and asserts that, thus, the Commission should encourage utilities to work with customers toward a mutually acceptable solution and require those utilities to file the return mechanism, including detailed documentation and worksheets so that the calculation of excess ADIT can be validated.[55]

33. Some commenters caution the Commission against mandating that public utilities adopt a single method to adjust their formula rates' income tax allowances. Instead, these commenters suggest that the Commission recognize public utilities' specific circumstances by evaluating proposed modifications on a case-by-case basis or recognizing that some formula rates already adjust the income tax allowance by the amortization of excess or deficient ADIT and, therefore, would not require revision.[56]

[53] Avangrid NOI Comments at 9, National Grid NOI Comments at 15, TAPS NOI Comments at 6.

[54] TAPS NOI Comments at 6 (citing *Alcoa Power Generating Inc.—Long Sault Div.*, 162 FERC ¶ 61,224).

[55] TAPS NOI Comments at 5-7.

[56] Exelon NOI Comments at 14-15; Indicated Customers NOI Comments at 12-13; MISO Transmission Owners NOI Comments at 17.

Indicated Transmission Owners argue that the Commission should make any evaluations on a single-issue basis.[57] The Oklahoma Attorney General suggests that the Commission could use ongoing proceedings, such as the show cause proceedings initiated against public utilities whose formula rates would not automatically adjust to reflect the lower federal corporate income tax rate of 21 percent, to revise formula rates such that the income tax allowance is adjusted by the amortization of excess or deficient ADIT.[58]

34. Consumer Advocates are concerned that absent Commission intervention, jurisdictional entities may begin to amortize their excess ADIT, thereby denying customers the full benefit of the Tax Cuts and Jobs Act. Consumer Advocates argue that to the extent any protected ADIT balances have been amortized to date, the Commission should require such excess protected ADIT amortization credits to be reversed and the liability balance restored to that of the implementation date of the Tax Cuts and Jobs Act.[59]

35. Regarding protected excess or deficient ADIT, commenters agree that the Commission has no need to change its existing regulations or precedent or depart from the Tax Cuts and Jobs Act's normalization provisions.[60] Regarding unprotected excess or

[57] Indicated Transmission Owners NOI Comments at 11-12.

[58] Oklahoma Attorney General NOI Comments at 6.

[59] Consumer Advocates NOI Comments at 4.

[60] AEP NOI Comments at 4-5; Ameren NOI Comments at 11; APPA and AMP NOI Comments at 5-6, 10; Avangrid NOI Comments at 8-9; Consumer Advocates NOI Comments at 6-7; DEMEC NOI Comments at 9; EEI NOI Comments at 14, 16-17;

deficient ADIT, commenters agree that the Commission should adopt a case-by-case approach for determining how quickly excess or deficient unprotected ADIT should be flowed back to or recovered from customers.[61]

3. Proposed Requirements

a. Formula Rates

36. We propose to require all public utilities with transmission formula rates to include a mechanism in their formula rates which decreases or increases their income tax allowances by any amortized excess or deficient ADIT, respectively, under 18 CFR 35.24. Such a mechanism is necessary because, as described above, the Tax Cuts and Jobs Act's reduction of the federal corporate income tax rate from 35 percent to 21 percent means public utilities have collected from customers funds in excess of what is due to the IRS for ADIT liabilities and, conversely for ADIT assets, funds from customers insufficient to satisfy IRS tax obligations. Similar to the proposed rate base

Eversource NOI Comments at 7; Exelon NOI Comments at 13; Indicated Customers NOI Comments at 8-9; Indicated Transmission Owners NOI Comments at 8-9; Kentucky Municipals NOI Comments at 6; MISO Transmission Owners NOI Comments at 8-11; National Grid NOI Comments at 10-11; New York Transco NOI Comments at 7-8; Oklahoma Attorney General NOI Comments at 6-7; PSEG NOI Comments at 7-8.

[61] AEP NOI Comments at 6-7 ("However, in the event the Commission develops a broadly applicable amortization period, AEP recommends that period be 25 years or longer"); Avangrid NOI Comments at 9-11; Dominion, Comments to NOI, Docket No. RM18-12-000, at 12 (filed on May 21, 2018); EEI NOI Comments at 17-18; Enable Interstate Pipelines, Comments to NOI, Docket No. RM18-12-000, at 36-37 (filed on May 21, 2018); Enbridge and Spectra, Comments to NOI, Docket No. RM18-12-000, at 26 (filed May 21, 2018); EQT Midstream, Comments to NOI, Docket No. RM18-12-000, at 13-14 (filed May 21, 2018); Eversource NOI Comments at 8-9; Exelon NOI Comments at 13-14; Indicated Transmission Owners NOI Comments at 9-10; National Grid NOI Comments at 11-13; New York Transco NOI Comments at 9.

adjustment requirements, these proposed income tax allowance adjustment requirements are intended to satisfy Order No. 144's requirement that the income tax allowance match the current tax cost and reflect the effects of any future changes to tax rates that may give rise to excess or deficient ADIT.

37. Similar to comments regarding adjustments to rate base, we agree with commenters to the NOI that prescribing a one-size-fits-all approach is not appropriate and that the public utilities with transmission formula rates should instead be allowed to propose any necessary changes to their rates on an individual basis. Accordingly, we do not propose that all public utilities with transmission formula rates must use a single method to adjust their income tax allowances for any amortized excess or deficient ADIT. Many public utilities with transmission formula rates use different formats of rate templates or formulas, and a single, prescriptive method, such as the requirement of a single line item, may not fully capture or transparently convey the amortization of excess or deficient ADIT. Additionally, recent filings by public utilities that proposed revisions to their formula rate templates to reflect changes in income tax rates by, among other things, incorporating mechanisms to return excess ADIT demonstrate that company-specific variations are necessary.[62]

[62] *See, e.g., Midcontinent Indep. Sys. Operator, Inc.*, 153 FERC ¶ 61,374; *Midcontinent Indep. Sys. Operator, Inc.*, 163 FERC ¶ 61,163; *Midcontinent Indep. Sys. Operator, Inc.,* 164 FERC ¶ 61,113 (2018); *Emera Maine*, 165 FERC ¶ 61,086 (2018).

38. Regarding the period over which the amortization of excess or deficient ADIT must occur, we believe that public utilities should follow the guidance provided in the Tax Cuts and Jobs Act, where available. As noted by commenters to the NOI, the Tax Cuts and Jobs Act provides a method of general applicability and requires public utilities to return excess protected ADIT[63] no more rapidly than over the life of the underlying asset using the Average Rate Assumption Method, or, where a public utility's books and underlying records do not contain the vintage account data necessary, it must use an alternative method.[64] In contrast, the Tax Cuts and Jobs Act does not specify what method public utilities must use for excess or deficient unprotected ADIT. We agree with commenters to the NOI that, because such a determination depends on the specific facts and circumstances for each public utility, a case-by-case approach to amortizing excess or deficient unprotected ADIT remains appropriate.

39. Consumer Advocates are concerned that a portion of the amounts allowable to be returned to customers under the Average Rate Assumption Method schedule would not be refunded due to the fact that any proposed tariff provisions to return excess ADIT as a result of this Proposed Rule will not be effective until after January 1, 2018. We

[63] While the Tax Cuts and Jobs Act does not mention deficient protected ADIT specifically, we expect that public utilities will recover such deficient ADIT in the same manner prescribed for excess protected ADIT.

[64] Tax Cuts and Jobs Act, Sec. 13001(b)(6)(A), 131 Stat. at 2099. If a public utility must use an alternative method, Commission precedent provides that the public utility should use the Reverse South Georgia Method for excess ADIT or the South Georgia Method for deficient ADIT. *See Memphis Light, Gas and Water Div. v. FERC*, 707 F.2d at 569.

acknowledge that in applying a tax normalization method (e.g., the Average Rate Assumption Method), public utilities are required to develop a schedule removing ADIT from rate base and returning it to customers, effective January 1, 2018, using the fastest allowable method to return the excess ADIT under the IRS' normalization requirements. However, these requirements represent only the fastest allowable return schedule and do not remove a public utility's obligation to return the excess ADIT. Any amounts allowed to be returned under the Average Rate Assumption Method schedule prior to the effective date of proposed tariff provisions made in compliance with the Proposed Rule should still be refunded to customers. In other words, the full regulatory liability for excess ADIT should be captured in rates, beginning on the effective date of any proposed tariff provision. We do not believe that any specific reforms are necessary to accomplish this because public utilities should not amortize an excess ADIT regulatory liability for accounting purposes until it is included in ratemaking.[65]

b. Stated Rates

40. We propose to require all public utilities with transmission stated rates to (1) determine the excess and deficient income tax caused by the Tax Cuts and Jobs Act's reduction to the federal corporate income tax rate and (2) return this amount to or recover this amount from customers under 18 CFR 35.24. We also propose for public utilities

[65] The description of Account 182.3 (Other regulatory assets) states, "The amounts recorded in this account are generally to be charged, *concurrently with the recovery of the amounts in rates*…" (emphasis added). 18 CFR part 101, Account 182.3 (Other Regulatory Assets).

with transmission stated rates to calculate this excess or deficient ADIT using the ADIT approved in their last rate cases. We believe calculating excess or deficient ADIT in this manner will allow public utilities with transmission stated rates to preserve their costs of service as accepted in their last rate case. We are not seeking to propose a specific way for public utilities with transmission stated rates to return or recover the excess or deficient income taxes to ratepayers; rather, we will evaluate each proposal on an individual basis. We believe the proposed reforms will increase the likelihood that those customers who contributed to the related ADIT accounts receive the benefit of the Tax Cuts and Jobs Act.

41. TAPS expresses concern that the customers of public utilities with transmission stated rates will lack sufficient information to evaluate any proposals to return or recover excess or deficient ADIT, respectively. We note that the Commission's regulations require public utilities filing changes to transmission rates to identify the effect of tax changes on those rates.[66] Accordingly, we expect that public utilities with stated rates would include in their compliance filings resulting from this Proposed Rule supporting information necessary to identify, at minimum, the following: (1) how any ADIT accounts were re-measured and the excess or deficient ADIT contained therein; (2) the accounting of any excess or deficient amounts in Accounts 182.3 and 254; (3) whether the excess or deficient ADIT is protected or unprotected; (4) the accounts to which the

[66] 18 CFR 35.13; 18 CFR 35.24.

excess or deficient ADIT will be amortized; and (5) the amortization period of the excess or deficient ADIT to be returned or recovered through the rates.

42. Finally, as noted above, public utilities with transmission stated rates must conform to the Tax Cuts and Jobs Act's requirements regarding the period over which the amortization of protected excess or deficient ADIT must occur. We will continue to analyze the appropriate amortization period for unprotected ADIT on a case-by-case basis.

C. Support for Excess and Deficient ADIT Calculation and Amortization

1. NOI

43. In the NOI, the Commission sought comment on whether it should require public utilities to provide to the Commission, on a one-time basis, additional information, such as supporting worksheets, to show the computation of excess or deficient ADIT and the corresponding flow-back of excess ADIT to customers or recovery of deficient ADIT from customers. The Commission asked commenters to address what types of information public utilities already record for ADIT-related accounting and whether balances and amortization of regulatory liability and asset accounts, computation of excess and deficient ADIT, delineation between protected and non-protected ADIT, and a description of the allocation method used to determine the transmission-related portion of excess or deficient ADIT would be appropriate to include in a supporting worksheet.[67]

[67] NOI, FERC Stats. & Regs. ¶ 35,582 at P 23.

2. Comments

44. Commenters were split regarding the requirement to provide additional worksheets. Some commenters assert that the Commission should not require any additional worksheets at this time.[68] These commenters generally assert that the implementation of general worksheet requirements would be burdensome on the industry.[69] They assert that any data should only be required to be submitted on a company by company basis, as necessary, rather than require a one-time proceeding for the purpose of all public utilities providing the data showing whether and how ADIT balances were re-measured.[70] Certain commenters assert that the Commission should not require additional worksheets as transmission formula rates and associated protocols already include mechanisms to provide details to customers.[71] Avangrid similarly states that the formula rate processes should be used to provide the level of transparency to verify the flowback of excess ADIT ultimately prescribed by the Commission. EEI states that if the Commission does require additional supporting information as part of EEI's

[68] *See* AEP NOI Comments at 8; Ameren NOI Comments at 16-18; Avangrid NOI Comments at 13-14; EEI NOI Comments at 20-22; Exelon NOI Comments at 15; Indicated Transmission Owners NOI Comments at 12; MISO Transmission Owners NOI Comments at 18-19; and PSEG NOI Comments at 11-12.

[69] *See* EEI NOI Comments at 20-21; Exelon NOI Comments at 15.

[70] EEI NOI Comments at 20.

[71] *See* AEP NOI Comments at 8; Ameren NOI Comments at 16-17; Avangrid NOI Comments at 13-14; Exelon NOI Comments at 15, Indicated Transmission Owners NOI Comments at 12; and MISO Transmission Owners NOI Comments at 18-19.

proposed show cause orders, the Commission should first provide its proposed financial template, in a rulemaking, to allow for review by public utilities and stakeholders. EEI adds that this would reduce the burden on individual public utilities and the Commission and would be similar to the approach leading up to the Gas Tax Final Rule.[72]

45. Other commenters, however, assert that the Commission should require electric public utilities to provide a one-time filing of additional information to provide transparency regarding excess and deficient ADIT, and how rates will be impacted by any changes.[73] APPA and AMP urge the Commission to require that supporting information be filed regarding excess or deficient ADIT, but not be limited to only ADIT-related material. They assert that public utilities should also describe, with supporting schedules, any current or projected effects on their books associated with the Tax Cuts and Jobs Act's changes to bonus depreciation, or any other potential rate-related impacts.[74] APPA and AMP further state that for public utilities with transmission formula rates, the utilities should provide as part of their annual updates, calculations showing excess ADIT amortization amounts that should be flowed back to customers in the applicable rate period. Consumer Advocates state that in addition to requiring a

[72] EEI NOI Comments at 21, n. 36.

[73] *See* APPA and AMP NOI Comments at 17-18; Consumer Advocates NOI Comments at 10-11; DEMEC NOI Comments at 11-12; Eversource NOI Comments at 11; Indicated Customers NOI Comments at 15; National Grid NOI Comments at 15-16; and New York Transco NOI Comments at 11.

[74] APPA and AMP NOI Comments at 17-18.

detailed worksheet identifying all book tax timing differences that comprise deferred tax liability balances, the Commission should evaluate the build-up of net operating losses as deferred tax assets. They assert that such balances should not automatically be inserted as an addition to regulated rate base.[75] New York Transco states that each public utility should be permitted to compile and present this additional information in the manner it deems most efficient and useful for stakeholders. New York Transco states that if stakeholders desire additional information, any interested party can seek that information consistent with the formula rate implementation protocols that address information sharing. While not objecting to the provision of additional information, National Grid states that the Commission should not impose this requirement until after December 2018 as the additional information will not be meaningful until after companies have set the final rate change balance after the filing of their fiscal year 2018 federal corporate income tax returns.[76]

3. Proposed Requirements

a. Formula Rates

46. We propose to require all public utilities with transmission formula rates to incorporate a new permanent worksheet into their transmission formula rates that will annually track information related to excess or deficient ADIT under 18 CFR 35.24. We believe that this reform is necessary to provide interested parties adequate transparency

[75] Consumer Advocates NOI Comments at 10-11.

[76] National Grid NOI Comments at 16.

regarding how public utilities with transmission formula rates adjust their rate bases and income tax allowances to account for excess or deficient ADIT. We also believe that requiring public utilities with transmission formula rates to provide this information on an annual basis rather than a one-time basis will better allow interested parties to follow excess or deficient ADIT as it is included in an annual revenue requirement and provide transparency as to any future changes in tax rates. We also believe that updating the proposed worksheet annually will better align with the nature of the vast majority of formula rates where calculation methodologies and input sources are accepted prior to those inputs being populated. Consequently, we do not propose that any worksheet be populated when submitted to the Commission for compliance, only that the function of the worksheet be clear.

47. Similar to other reforms proposed in this Proposed Rule, we do not propose a pro forma worksheet that must be adopted by all public utilities with transmission formula rates; rather, we propose requiring general categories of information that each excess or deficient ADIT tracking worksheet must contain. We propose that each excess or deficient ADIT worksheet must, at minimum, include the following: (1) how any ADIT accounts were re-measured and the excess or deficient ADIT contained therein; (2) the accounting of any excess or deficient amounts in Accounts 182.3 and 254; (3) whether the excess or deficient ADIT is protected or unprotected; (4) the accounts to which the excess or deficient ADIT are amortized; and (5) the amortization period of the excess or deficient ADIT being returned or recovered through the rates. Because we do not propose to define the form any worksheet or worksheets must take, only the

information it must contain, we propose evaluating such worksheet or worksheets on an individual basis. We also request comments on whether we should consider additional guiding principles to those described above.

48. We disagree with commenters to the NOI that argue that providing such information is overly burdensome for the industry. Public utilities with transmission formula rates will already have gathered the information we propose to require in the worksheets to re-measure their ADIT balances and develop amortization schedules following the Tax Cuts and Jobs Act's reduction of the federal corporate income tax rate. Further, the Commission has already accepted worksheets that convey information similar to the proposed requirements outlined above.[77]

49. We also disagree with commenters to the NOI that public utilities' existing formula rate protocols should preclude the Commission from proposing an excess or deficient ADIT worksheet. While the Commission established that formula rate protocols should allow for the provision of any information necessary to understand the inputs to the rate in order to provide sufficient transparency to interested parties, the Commission has since required public utilities to revise their formula rates to include greater detail where it has deemed that certain inputs to the rate are complex enough to warrant prior understanding of their effect.[78] As related to excess and deficient ADIT,

[77] *See, e.g., Arizona Public Service Company*, Docket No. ER18-975-001 (May 22, 2018) (delegated order).

[78] *See, e.g., Midcontinent Indep. Sys. Operator, Inc.*, 153 FERC ¶ 61,374 at P 14 (directing certain transmission companies to revise their transmission formula rates to

we believe the proposed worksheet will allow interested parties to ensure they are receiving the benefits of the Tax Cuts and Jobs Act, as well as to track over time any changes in the rate effects of the tax change as, for example, assets are sold or retired.

b. Stated Rates

50. As described above in the proposal for return of excess ADIT or recovery of deficient ADIT, we believe that the Commission's existing regulations require public utilities with transmission stated rates to provide sufficient support for any proposed tax-related changes. As a result, we do not propose any additional information requirements for public utilities with transmission stated rates.

III. Proposed Compliance Procedures

51. We propose to require each public utility with transmission stated or formula rates to submit a compliance filing within 90 days of the effective date of any subsequent final rule in this proceeding to revise its transmission formula or stated rates, as necessary, to demonstrate that it meets the requirements set forth in any subsequent final rule.

52. Some public utilities with transmission formula rates may already have mechanisms in place in their rates that address the issues and concerns addressed by any subsequent final rule. Where these provisions would be modified by any subsequent final rule, the public utility must either comply with any subsequent final rule or demonstrate

include worksheets to ensure appropriate transparency). The Commission has also regularly required certain revisions to new formula rates to provide greater transparency. *See, e.g., Xcel Energy Sw. Transmission Co., LLC*, 149 FERC ¶ 61,182 (2014); *Xcel Energy Transmission Dev. Co., LLC*, 149 FERC ¶ 61,181 (2014); *Transource Wisconsin, LLC*, 149 FERC ¶ 61,180 (2014); *Transource Kansas, LLC,* 151 FERC ¶ 61,010 (2015).

that these previously approved variations continue to be consistent with or superior to the requirements of any subsequent final rule.

53. The Commission will assess whether each compliance filing satisfies the proposed requirements stated above and issue additional orders as necessary to ensure that each public utility with transmission stated or formula rates meets the requirements of the subsequent final rule.

IV. Information Collection Statement

54. The collection of information contained in this Proposed Rule is subject to review by the Office of Management and Budget (OMB) regulations under section 3507(d) of the Paperwork Reduction Act of 1995 (PRA).[79] OMB's regulations require approval of certain informational collection requirements imposed by an agency.[80] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

55. The reforms proposed in this Proposed Rule address public utilities that have transmission formula rates and transmission stated rates. The reforms related to transmission formula rates represent new requirements for these entities under the

[79] 44 U.S.C. 3507(d).

[80] 5 CFR 1320.11.

Commission's regulations in 18 CFR 35.24, which we believe are necessary because of the dramatic changes in the rate structure of the electric transmission industry since this provision was originally promulgated in 1981.[81] These new requirements would require each public utility with a transmission formula rate to revise its rate so that any excess or deficient ADIT is properly reflected in its revenue requirement following a change in tax rates, such as those established by the Tax Cuts and Jobs Act. Additionally, each public utility with a transmission formula rate would be required to incorporate a new permanent worksheet into its transmission formula rate to increase transparency.

56. The reforms required by this Proposed Rule will require each public utility with stated rates to calculate the excess and deficient ADIT caused by the Tax Cuts and Jobs Act and to return to or recover from customers those amounts. This reform is intended to increase the likelihood that customers who contributed to the excess ADIT balance timely receive the benefits of the Tax Cuts and Jobs Act.

57. The reforms proposed in this Proposed Rule would require compliance filings with the Commission by each public utility with transmission stated or formula rates to allow the Commission the opportunity to determine whether each such public utility met the requirements detailed in this Proposed Rule.

58. We anticipate the reforms proposed in this Proposed Rule, once implemented, would not significantly change currently existing burdens on an ongoing basis. With regard to those public utilities with transmission stated or formula rates that believe that

[81] *See* discussion *infra* Section II.E.

they already comply with the reforms proposed in this Proposed Rule, they could demonstrate their compliance in the filing required 90 days after the effective date of the final revision in this proceeding. We will submit the proposed reporting requirements to OMB for its review and approval under section 3507(d) of the Paperwork Reduction Act.[82]

59. While we expect the adoption of the reforms proposed in this Proposed Rule to provide significant benefits, the Commission understands that implementation can be a complex and costly endeavor. We solicit comments on the accuracy of provided burden and cost estimates and any suggested methods for minimizing the respondents' burdens.

60. Burden Estimate and Information Collection Costs: We believe that the burden estimates below are representative of the average burden on respondents. The estimated burden and cost for the requirements contained in this Proposed Rule follow.

[82] 44 U.S.C. 3507(d).

RM19-5-000 NOPR (Public Utility Transmission Rate Changes to Address Accumulated Deferred Income Taxes)						
	Number of Respondents (1)	**Annual Number of Responses per Respondent (2)**	**Total Number of Responses (1)*(2)=(3)**	**Average Burden & Cost Per Response[83] (4)**	**Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)**	**Cost per Respondent ($) (5)÷(1)**
Revising formula rates so that excess ADIT is deducted and/or deficient ADIT is added to rate base (one-time)[84]	106	1	106	8 hours; $736	848 hours; $78,016	$736
Revising formula rates so that any excess and/or deficient ADIT is amortized (one-time)	106	1	106	8 hours; $736	848 hours; $78,016	$736

[83] The loaded hourly wage figure (includes benefits) is based on the average of the occupational categories for 2017 found on the Bureau of Labor Statistics website (http://www.bls.gov/oes/current/naics2_22.htm):

Accountant (Occupation Code: 13-2011): $56.59

Management (Occupation Code: 11-0000): $94.28

Legal (Occupation Code: 23-0000): $143.68

Office and Administrative Support (Occupation Code: 43-0000): $41.34

These various occupational categories' wage figures are averaged and weighted equally as follows: ($94.28/hour + $61.55/hour + $66.90/hour + $143.68/hour) ÷ 4 = $91.60/hour. The resulting wage figure is rounded to $92.00/hour for use in calculating wage figures in the NOPR in Docket No. RM19-5-000.

[84] One-time burdens apply in Year One only. There will be no subsequent burden in Years 2 and beyond.

Revising transmission stated rates to return or recover excess or deficient ADIT (one-time)	31	1	31	15 hours; $1,380	465 hours; $42,780	$1,380
Requiring public utilities with transmission formula rates to incorporate a new permanent worksheet that will annually track ADIT information (one-time)	106	1	106	40 hours; $3,680	4,240 hours; $390,080	$3,680
Total (Stated Rates)[85]			**31**		**465 hours; $42,780**	
Total (Formula Rates)[86]			**318**		**5,936 hours; $546,112**	
TOTAL			**349**		**6,532 hours; $588,892**	

Cost to Comply: We have projected the total cost of compliance as follows:[87]

[85] Total for Public Utilities with Transmission Stated Rates

[86] Total for Public Utilities with Transmission Formula Rates

[87] For a public utility transmission provider with transmission formula rates, the costs for Year 1 would consist of filing proposed changes to its transmission formula rates, including the addition of a new permanent worksheet, with the Commission within 90 days of the effective date of the final revision plus initial implementation. The Commission does not expect any ongoing costs beyond the initial compliance in Year 1. For a public utility transmission provider with transmission stated rates, the costs for Year 1 would consist of filing proposed changes to its transmission stated rates that allow it to return to or recover from customers any excess or deficient ADIT caused by the Tax Cuts and Jobs Act with the Commission within 90 days of the effective date of the final revision plus initial implementation.

- Year 1: $546,112 ($5,152/utility) for public utilities with transmission formula rates; $42,780 ($1,380/utility) for public utilities with transmission stated rates.
- Year 2: $0

After Year 1, the reforms proposed in this Proposed Rule, once implemented, would not significantly change existing burdens on an ongoing basis.

Title: FERC-516, Electric Rate Schedules and Tariff Filings.

Action: Proposed revisions to an information collection.

OMB Control No.: 1902-0096

Respondents for this Proposal: Businesses or other for profit and/or not-for-profit institutions.

Frequency of Information: One-time during year one.

Necessity of Information: The Federal Energy Regulatory Commission makes this Proposed Rule to ensure that (1) rate base neutrality is preserved following enactment of the Tax Cuts and Jobs Act; (2) the reduction in ADIT on the books of rate-regulated companies that was collected from customers but is no longer payable to the IRS due to the Tax Cuts and Jobs Act is returned to or recovered from ratepayers consistent with general ratemaking principles; and (3) there is increased transparency for the process of excess and deficient ADIT calculation and amortization.

Internal Review: We have reviewed the proposed changes and have determined that such changes are necessary. These requirements conform to the Commission's need for efficient information collection, communication, and management within the energy industry. We have specific, objective support for the burden estimates associated with the information collection requirements.

61. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director], e-mail: DataClearance@ferc.gov, phone: (202) 502-8663, fax: (202) 273-0873. Comments concerning the collection of information and the associated burden estimate(s), may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395-0710, fax: (202) 395-7285]. Due to security concerns, comments should be sent electronically to the following e-mail address: oira_submission@omb.eop.gov. Comments submitted to OMB should include FERC-516 and OMB Control No. 1902-0096.

V. Environmental Analysis

62. We are required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[88] The actions proposed to be taken in this Proposed Rule fall within the categorical exclusion under section 380.4(a)(15) of the Commission's regulations. This

[88] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987) (cross-referenced at 41 FERC ¶ 61,284).

section provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classification, and services.[89] The revisions proposed in this Proposed Rule fall within the categorical exemptions provided in the Commission's regulations, and as a result neither an Environmental Impact Statement nor an Environmental Assessment is required.

VI. Regulatory Flexibility Act Certification

63. The Regulatory Flexibility Act of 1980 (RFA)[90] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities. The RFA does not mandate any particular outcome in a rulemaking. It only requires consideration of alternatives that are less burdensome to small entities and an agency explanation of why alternatives were rejected.

64. The Small Business Administration (SBA) revised its size standards (effective January 22, 2014) for electric utilities from a standard based on megawatt hours to a standard based on the number of employees, including affiliates. Under SBA's standards, some transmission owners will fall under the following category and

[89] 18 CFR 380.4(a)(15).

[90] 5 U.S.C. 601-612.

associated size threshold: electric bulk power transmission and control, at 500 employees.[91]

65. We estimate that the total number of public utility transmission providers with formula rates that would have to develop revisions to their formula rates, including the addition of a new permanent worksheet, and make compliance filings in response to this Proposed Rule is 106. Of these, we estimate that approximately 43 percent are small entities (approximately 46 entities). We estimate the average total cost to each of these entities will be $5,152 in Year 1 and $0 in subsequent years. In addition, we estimate that the total number of public utility transmission providers with stated rates that will have to calculate the excess and deficient income tax to return to or recover from customers is 31. Of these, we estimate that approximately 43 percent are small entities (approximately 13 entities). We estimate the average total cost to each of these entities will be between $1,380 in Year One and $0 in subsequent years. According to SBA guidance, the determination of significance of impact "should be seen as relative to the size of the business, the size of the competitor's business, and the impact the regulation has on larger competitors."[92] We do not consider the estimated burden to be a significant economic

[91] 13 CFR 121.201, Sector 22 (Utilities), NAICS code 221121 (Electric Bulk Power Transmission and Control).

[92] U.S. Small Business Administration, *A Guide for Government Agencies How to Comply with the Regulatory Flexibility Act*, at 18 (May 2012), https://www.sba.gov/sites/default/files/advocacy/rfaguide_0512_0.pdf.

impact. As a result, we certify that the revisions proposed in this Proposed Rule will not have a significant economic impact on a substantial number of small entities.

VII. Comment Procedures

66. We invite interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due [**INSERT DATE 30 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER**]. Comments must refer to Docket No. RM19-5-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

67. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at http://www.ferc.gov. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

68. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street N.E., Washington, DC, 20426.

69. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VIII. Document Availability

70. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, N.E., Room 2A, Washington D.C. 20426.

71. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

72. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202)502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

By direction of the Commission. Commissioner McIntyre is not voting on this order.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Note: Appendix A will not be published in the Federal Register.

Appendix A – List of Commenters to NOI

Short Name	Commenter
AEP	American Electric Power Service Corporation
Ameren	Ameren Services Company on behalf of Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois, and Ameren Transmission Company of Illinois
AOPL	Association of Oil Pipe Lines
APGA	American Public Gas Association
APPA and AMP	American Public Power Association and American Municipal Power, Inc.
Avangrid	Avangrid Networks, Inc.
Berkshire	Berkshire Hathaway Energy Pipeline Group
Boardwalk	Boardwalk Pipeline Partners LP
CAPP	Canadian Association of Petroleum Producers
Consumer Advocates	Office of the Attorney General of the Commonwealth of Massachusetts; the Ohio Consumers' Counsel; the Maryland Office of People's Counsel; the Nevada Bureau of Consumer Protection; the Delaware Division of the Public Advocate; the Pennsylvania Office of Consumer Advocate; the Citizens Utility Board of Wisconsin; and the Indiana Office of Utility Consumer Counselor
DEMEC	Delaware Municipal Electric Corporation, Inc.
Dominion Energy Gas Pipelines	Dominion Energy Transmission, Inc.; Dominion Energy Carolina Gas Transmission, LLC; Dominion Energy Quester Pipeline, LLC; Dominion Energy Overthrust Pipeline, LLC; and Questar Southern Trails Pipeline Company

EEI	Edison Electric Institute
Enable Interstate Pipelines	Enable Mississippi River Transmission, LLC and Enable Gas Transmission, LLC
Enbridge and Spectra	Enbridge Energy Partners, L.P. and Spectra Energy Partners, LP
EQT Midstream	EQT Midstream Partners, LP
Eversource	Eversource Energy Service Company
Exelon	Exelon Corporation
Indicated Customers	Central Electric Power Cooperative, Inc., North Carolina Electric Membership Corporation, Southern Maryland Electric Cooperative, Inc., and the New Jersey Division of Rate Counsel
Indicated Local Distribution Companies	Atmos Energy Corporation; the City of Charlottesville, Virginia; the City of Richmond, Virginia; the Easton Utilities Commission; Exelon Corporation; and Washington Gas Light Company
Indicated Transmission Owners	American Electric Power Service Corporation; Dominion Energy Services, Inc., on behalf of Virginia Electric and Power Company d/b/a Dominion Energy Virginia; Duquesne Light Company; Exelon Corporation; FirstEnergy Service Company, on behalf of American Transmission Systems, Incorporated; Jersey Central Power & Light Company; Mid-Atlantic Interstate Transmission, LLC; West Penn Power Company; The Potomac Edison Company; Monongahela Power Company; and PPL Electric Utilities Corp.
INGAA	Interstate Natural Gas Association of America
ITC Great Plains	ITC Great Plains, LLC
Kentucky Municipals	Frankfort Plant Board of Frankfort, Kentucky; Barbourville Utility Commission of the City of Barbourville, City; Utilities Commission of the City of Corbin; and the Cities of Bardwell, Berea, Falmouth, Madisonville, and Providence, Kentucky

Kinder Morgan Entities	Natural Gas Pipeline Company of America LLC; Tennessee Gas Pipeline Company, L.L.C.; Southern Natural Gas Company, L.L.C.; Colorado Interstate Gas Company, L.L.C.; Wyoming Interstate Company, L.L.C.; El Paso Natural Gas Company, L.L.C.; Mojave Pipeline Company, L.L.C.; Bear Creek Storage Company, L.L.C.; Cheyenne Plains Gas Pipeline Company, L.L.C.; Elba Express Company, L.L.C.; Kinder Morgan Louisiana Pipeline LLC; Southern LNG Company, L.L.C.; and TransColorado Gas Transmission Company LLC
Kinder Morgan Subsidiaries	SFPP, L.P.; Calnev Pipe Line, LLC; and Kinder Morgan Cochin, LLC
MISO Transmission Owners	Ameren Services Company, as agent for Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois and Ameren Transmission Company of Illinois; American Transmission Company LLC; Central Minnesota Municipal Power Agency; City Water, Light & Power (Springfield, IL); Cleco Power LLC; Cooperative Energy; Dairyland Power Cooperative; Duke Energy Business Services, LLC for Duke Energy Indiana, LLC; East Texas Electric Cooperative; Entergy Arkansas, Inc.; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy New Orleans, LLC; Entergy Texas, Inc.; Great River Energy; Indiana Municipal Power Agency; Indianapolis Power & Light Company; International Transmission Company d/b/a ITC*Transmission*; ITC Midwest LLC; Lafayette Utilities System; Michigan Electric Transmission Company, LLC; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Missouri River Energy Services; Montana-Dakota Utilities Co.; Northern Indiana Public Service Company LLC; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Prairie Power Inc.; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); Southern Minnesota Municipal Power Agency; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc.

National Grid	National Grid USA
Natural Gas Indicated Shippers	Aera Energy, LLC; Anadarko Energy Services Company; Apache Corporation; BP Energy Company; ConocoPhillips Company; Hess Corporation; Occidental Energy Marketing, Inc.; Petrohawk Energy Corporation; and XTO Energy, Inc.
New York Transco	New York Transco LLC
Oklahoma Attorney General	Mike Hunter, Oklahoma Attorney General
PJM	PJM Interconnection, L.L.C.
Plains	Plains Pipeline, L.P.
Process Gas and American Forest and Paper	Process Gas Consumers Group and American Forest and Paper Association
PSEG	Public Service Electric and Gas Company
Tallgrass Pipelines	Trailblazer Pipeline Company LLC; Tallgrass Interstate Gas Transmission, LLC; and Rockies Express Pipeline LLC
TAPS	Transmission Access Policy Study Group
TransCanada	TransCanada Corporation
United Airlines Petitioners	United Airlines, Inc.; American Airlines, Inc.; Delta Air Lines, Inc.; Southwest Airlines, Co.; BP West Coast Products LLC; ExxonMobil Oil Corporation; Chevron Products Company; HollyFrontier Refining & Marketing LLC; Valero Marketing and Supply Company; Airlines for America; and the National Propane Gas Association
Williams	Williams Companies, Inc.

165 FERC ¶ 61,115
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Docket No. PL19-2-000

Accounting and Ratemaking Treatment of Accumulated Deferred Income Taxes and Treatment Following the Sale or Retirement of an Asset

(Issued November 15, 2018)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Policy Statement.

SUMMARY: In this Policy Statement, the Federal Energy Regulatory Commission (Commission) states its policy regarding the treatment of Accumulated Deferred Income Taxes for both accounting and ratemaking purposes as to Commission-jurisdictional public utilities, natural gas pipelines and oil pipelines, in light of the Tax Cuts and Jobs Act of 2017. In addition, the Commission addresses the accounting and ratemaking treatment of Accumulated Deferred Income Taxes following the sale or retirement of an asset.

EFFECTIVE DATE: This Policy Statement will become effective **[date of publication in the *Federal Register*].**

FOR FURTHER INFORMATION CONTACT:

Sharli Silva (Legal Information)
Office of the General Counsel
888 First Street, NE
Washington, DC 20426
(202) 502-8719
Sharli.Silva@ferc.gov

Bryan Wheeler (Technical Information)
Office of Energy Markets Regulation
Federal Energy Regulatory Commission
888 First Street, NE

Washington, DC 20426
(202) 502-8497
Bryan.Wheeler@ferc.gov

Monil Patel (Technical Information)
Office of Energy Markets Regulation
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(202) 502-8296
Monil.Patel@ferc.gov

Kimberly Horner (Technical Information)
Office of Enforcement
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
(202) 502-8623
Kimberly.Horner@ferc.gov

<u>SUPPLEMENTARY INFORMATION</u>:

165 FERC ¶ 61,115
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Neil Chatterjee, Chairman;
Cheryl A. LaFleur and Richard Glick.

Accounting and Ratemaking Treatment of Accumulated Deferred Income Taxes and Treatment Following the Sale or Retirement of an Asset — Docket No. PL19-2-000

POLICY STATEMENT

(Issued November 15, 2018)

1. In this Policy Statement, the Federal Energy Regulatory Commission (Commission) states its policy regarding the treatment of Accumulated Deferred Income Taxes (ADIT) for both accounting and ratemaking purposes as to Commission-jurisdictional public utilities, natural gas pipelines, and oil pipelines, in light of the Tax Cuts and Jobs Act of 2017.[1] The Commission also addresses the accounting and ratemaking treatment of ADIT following the sale or retirement of an asset.

I. Background

A. Tax Cuts and Jobs Act

2. On December 22, 2017, the President signed into law the Tax Cuts and Jobs Act. The Tax Cuts and Jobs Act, among other things, reduced the federal corporate income tax

[1] An Act to provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018, Pub. L. No. 115-97, 131 Stat. 2054 (2017) (Tax Cuts and Jobs Act).

rate from 35 percent to 21 percent, effective January 1, 2018.[2] This means that, beginning January 1, 2018, companies subject to the Commission's jurisdiction will compute income taxes owed to the Internal Revenue Service (IRS) based on a 21 percent tax rate. The tax rate reduction will result in less corporate income tax expense going forward.

3. Importantly, the tax rate reduction will also result in a reduction in ADIT liabilities and ADIT assets on the books of rate-regulated companies. ADIT balances are accumulated on the regulated books and records of such regulated companies based on the requirements of the Uniform System of Accounts (USofA).[3] ADIT arises from timing differences between the method of computing taxable income for reporting to the IRS and the method of computing income for regulatory accounting and ratemaking purposes.[4] As a result of the Tax Cuts and Jobs Act reducing the federal corporate income tax rate from 35 percent to 21 percent, a portion of an ADIT liability that was collected from customers will no longer be due from public utilities, natural gas pipelines and oil pipelines to the IRS and is considered excess ADIT.

[2] *Id.* Sec. 13001, 131 Stat. at 2096.

[3] *See* Definition of Accounts 182.3 and Account 254, 18 CFR part 101, *Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act*; *see* Definition of Accounts 182.3 and Account 254, 18 CFR part 201, *Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act; see* General Instructions 1-12, Accounting for Income Taxes, 18 CFR part 352, *Uniform Systems of Accounts Prescribed for Oil Pipeline Companies Subject to the Provisions of the Interstate Commerce Act*.

[4] *See* 18 CFR 35.24(d)(2) (2018).

B. Order No. 144

4. The purpose of tax normalization is to match the tax effects of costs and revenues with the recovery in rates of those same costs and revenues.[5] As noted above, timing differences may exist between the method of computing taxable income for reporting to the IRS and the method of computing income for regulatory accounting and ratemaking purposes. The tax effects of these differences are placed in a deferred tax account to be used in later periods when the differences reverse.[6]

5. The Commission established this policy of tax normalization in Order No. 144 where it required use of "the provision for deferred taxes [(i.e., ADIT)] as a mechanism for setting the tax allowance at the level of current tax cost."[7] In keeping with this normalization policy, and as relevant to the Tax Cuts and Jobs Act's reduction of the federal corporate income tax rate, the Commission in Order No. 144 also required adjustments in the ADIT of public utilities' cost of service when excessive or deficient ADIT has been created as a result of changes in tax rates.[8] Furthermore, the Commission required "a rate applicant to compute the income tax component in its cost of service by making provision for any excess

[5] *Tax Normalization for Certain Items Reflecting Timing Differences in the Recognition of Expenses or Revenues for Ratemaking and Income Tax Purposes*, Order No. 144, FERC Stats. & Regs. ¶ 30,254 at 31,522, 31,530 (1981), *order on reh'g*, Order No. 144-A, FERC Stats. & Regs. ¶ 30,340 (1982).

[6] Order No. 144, FERC Stats. & Regs. ¶ 30,254 at 31,554.

[7] *Id.* at 31,530.

[8] *Id.* at 31,519.

or deficiency in its deferred tax reserves resulting . . . from tax rate changes."[9] The Commission required that such provision be consistent with a Commission-approved ratemaking method made specifically applicable to the rate applicant.[10] Where no ratemaking method has been made specifically applicable, the Commission required the rate applicant to advance some method in its next rate case.[11] The Commission stated that it would determine the appropriateness of any proposed method on a case-by-case basis, but as the issue is resolved in a number of cases, a method with wide applicability may be adopted.[12] The Commission codified the requirements of Order No. 144 in its regulations in 18 CFR 35.24.[13]

1. <u>Public Utilities – 18 CFR 35.24</u>

6. Originally promulgated in Order No. 144, the Commission's regulations in 18 CFR 35.24 provide requirements for the proper ratemaking treatment of the tax effects of all

[9] Order No. 144, FERC Stats. & Regs. ¶ 30,254 at 31,560. *See also* 18 CFR 35.24(c)(1)(ii); 18 CFR 35.24(c)(2).

[10] Order No. 144, FERC Stats. & Regs. ¶ 30,254 at 31,560. *See also* 18 CFR 35.24(c)(3).

[11] Order No. 144, FERC Stats. & Regs. ¶ 30,254 at 31,560.

[12] *Id*. *See also* 18 CFR 35.24(c)(3).

[13] Originally promulgated as part of Order No. 144, the regulatory text was redesignated as 18 CFR 35.25 in Order No. 144-A. *See* Order No. 144-A, FERC Stats. & Regs. ¶ 30,340 at 30,140. In Order No. 545, the Commission again redesignated the regulatory text to its present designation as 18 CFR 35.24. *See Streamlining Electric Power Regulation,* Order No. 545, FERC Stats. & Regs. ¶ 30,955, at 30,713 (1992) (cross-referenced at 61 FERC ¶ 61,207).

transactions for which there are timing differences.[14] Under this section, a public utility must account for excess or deficient ADIT when computing the income tax component of its cost of service.[15] Additionally, in accounting for this excess or deficient ADIT, a public utility is required to apply the ratemaking method that has been specifically approved by the Commission for that public utility.[16] Where no such ratemaking method exists, a public utility may choose which ratemaking method to apply and the reasonableness of that ratemaking method will be determined on a case-by-case basis by the Commission.[17]

2. Natural Gas Pipelines – 18 CFR 154.305

7. Order No. 144 also promulgated the Commission's regulations regarding tax normalization for natural gas pipelines which were originally located in part 2 of the regulations as section 2.202.[18] Order No. 144-A redesignated the tax normalization regulations for natural gas pipelines by removing them from part 2 of the Commission's regulations and placing them in part 154.[19] Subsequently, Order No. 582 redesignated the regulatory text in that part with respect to natural gas pipelines to its current designation in

[14] *See id.*

[15] *See* 18 CFR 35.24(c)(1)(ii), (c)(2).

[16] *See* 18 CFR 35.24(c)(3).

[17] *See id.*

[18] Order No. 144, FERC Stats. & Regs. ¶ 30,254.

[19] Order No. 144-A, FERC Stats. & Regs.¶ 30,340 at 30,140. The Commission deemed part 154 a more appropriate location because tax normalization is required to be used by natural gas pipelines in filing their rate applications and the regulations that govern the filing of such rate applications are located in part 154. *Id.*

section 154.305, and made various revisions in that section.[20] The section requires a natural gas pipeline making a rate filing under the Natural Gas Act to compute the income tax component of its cost of service by using tax normalization for all transactions.[21] More specifically, the section requires natural gas pipelines to reduce rate base by the balances that are properly recordable in USofA Account 281 (Accumulated deferred income taxes-accelerated amortization property), Account 282 (Accumulated deferred income taxes—other property), and Account 283 (Accumulated deferred income taxes—other).[22] Conversely, rate base must be increased by balances that are properly recordable in Account 190 (Accumulated deferred income taxes).[23] The section also requires natural gas pipelines to compute the income tax component in its cost of service by including a provision for amortizing excess or deficiency in deferred taxes. This is done by applying a Commission-approved ratemaking method made specifically applicable to the natural gas pipeline for determining the cost-of-service provision: (1) if the natural gas pipeline has not provided deferred taxes in the same amount that would have accrued had tax normalization always been applied or (2) if, as a result of changes in tax rates, the accumulated provision for

[20] 18 CFR 154.305 (2018). *See* Order No. 582, *Filing and Reporting Requirements for Interstate Natural Gas Company Rate Schedules and Tariffs,* FERC Stats. & Regs. ¶ 31,025 (1995), *order on reh'g,* Order No. 582-A, FERC Stats. & Regs. ¶ 31,043 (1996), *order on clarification*, FERC Stats. & Regs. ¶ 31,037 (1996). The tax normalization regulations were moved from 18 CFR 154.63a to 154.305.

[21] 18 CFR 154.305.

[22] 18 CFR 154.305(c)(1).

[23] *Id.*

deferred taxes becomes deficient in, or in excess of, amounts necessary to meet future tax liabilities.[24] Similar to the tax normalization regulations for public utilities, if the Commission has not approved a specific ratemaking method specifically applicable to the natural gas pipeline, then the natural gas pipeline must use a previously approved ratemaking method.[25] The Commission will determine whether such method is appropriate on a case-by-case basis.[26]

3. Oil Pipelines

8. Unlike the Commission's regulations applicable to public utilities and natural gas pipelines, there is no tax normalization section under the Commission's regulations for oil pipelines. Instead, the Commission's regulations for oil pipelines under the USofA General Instructions, 1-12 *Accounting for Income Taxes*, require that when income tax rates are changed, oil pipelines reduce or increase their ADIT balances immediately by the full amount of the excess or deficient tax reserve.[27] Specifically, section (b) requires oil pipelines to apply the enacted tax rate in determining the amount of deferred taxes and adjust their deferred tax liabilities and assets for the effect of the change in tax law or rates

[24] 18 CFR 154.305(d). Such amounts must be included as an addition or reduction to rate base until the deficiency or excess is fully amortized using the Commission approved ratemaking method. *Id.*

[25] 18 CFR 154.305(d)(3).

[26] *Id.*

[27] 18 CFR part 352, General Instructions 1-12, Accounting for Income Taxes.

in the period that the change is enacted.[28] The section further requires the adjustment to be recorded in the appropriate deferred tax balance sheet accounts based on the nature of the temporary difference and the related classification requirements of the account.[29]

4. Prior Accounting Guidance for Public Utilities and Natural Gas Pipelines

9. In Docket No. AI93-5-000, the Chief Accountant issued accounting guidance on the proper accounting for income taxes.[30] Among other matters, the accounting guidance directed public utilities and natural gas companies to adjust their deferred tax liabilities and assets for the effect of the change in tax law or rates in the period that the change is enacted.[31] The guidance stated that adjustments should be recorded in the appropriate deferred tax balance sheet accounts (Accounts 190, 281, 282 and 283) based on the nature of the temporary difference and the related classification requirements of the accounts.[32] Further, if as a result of action by a regulator, it is probable that the future increase or decrease in taxes payable due to the change in tax law or rates will be recovered from or returned to customers through future rates, an asset or liability should be recognized in

[28] *Id.*

[29] *Id.*

[30] *See Accounting for Income Taxes*, Docket No. AI93-5-000, at Item 8 (Apr. 23, 1993).

[31] *Id.*

[32] *Id.*

Account 182.3 (Other Regulatory Assets), or Account 254 (Other Regulatory Liabilities), as appropriate, for that probable future revenue or reduction in future revenue.[33]

C. Notice of Inquiry

10. Following the enactment of the Tax Cuts and Jobs Act, the Commission issued a Notice of Inquiry seeking comments on, among other things, whether, and if so, how, the Commission should address the effects on ADIT of the Tax Cuts and Jobs Act.[34] The Commission noted that the Tax Cuts and Jobs Act's reduction to the federal corporate income tax rate would potentially create excess or deficient ADIT on the books of public utilities.[35] As relevant to the guidance provided in this Policy Statement, the Commission sought comments on the treatment of ADIT for assets sold or retired after December 31, 2017, and the amortization of excess and deficient ADIT.[36]

II. Discussion

11. This Policy Statement states our requirements regarding the treatment of ADIT in light of the tax rate reduction implemented in the Tax Cuts and Jobs Act. Specifically, we provide guidance regarding: (1) the accounts in which public utilities, natural gas pipelines, and oil companies should record the amortization of excess and/or deficient ADIT for

[33] *Id.*

[34] *Inquiry Regarding the Effect of the Tax Cuts and Jobs Act on Commission-Jurisdictional Rates*, FERC Stats. & Regs. ¶ 35,582 (2018) (NOI). In this Policy Statement, we refer to the comments filed in response to the NOI. A list of commenters in that proceeding and the abbreviated names used in this Policy Statement appears in Appendix A.

[35] NOI, FERC Stats. & Regs. ¶ 35,582 at P 13.

[36] *Id.* PP 20-22.

accounting purposes and ratemaking purposes and (2) whether, and if so how, such entities should address excess and/or deficient ADIT that is recorded on the books of public utilities, natural gas pipelines, and oil companies after December 31, 2017, as a result of assets being sold or retired for both accounting and ratemaking purposes.

12. First, we clarify that for both accounting purposes and ratemaking purposes, public utilities and natural gas companies should record the amortization of the excess and/or deficient ADIT recorded in Account 254 (Other Regulatory Liabilities) and/or Account 182.3 (Other Regulatory Assets) by recording the offsetting entries to Account 410.1 (Provision for Deferred Income Taxes, Utility Operating Income) or Account 411.1 (Provision for Deferred Income Taxes – Credit, Utility Operating Income), as required by the USofA. We further clarify that for accounting purposes oil pipelines should adjust their ADIT balances to reflect the change in federal income tax rates with offsetting entries to the appropriate income statement account, as required by the USofA. Accordingly, oil pipeline companies will not record excess or deficient ADIT for accounting purposes. As detailed below, we also clarify that oil pipelines should provide additional disclosures in the Notes that accompany their FERC Form No. 6, Annual Report of Oil Pipeline Companies (Form No. 6).

13. Second, for accounting purposes, we reiterate that public utilities and natural gas pipelines must continue to follow the accounting guidance issued by the Chief Accountant in Docket No. AI93-5-000 with respect to changes in tax law or rates. To ensure transparency in the accounting adjustments to the deferred tax accounts, we clarify that

entities should provide additional disclosures in their 2018 FERC annual financial filing within the Notes to the Financial Statements as detailed below.

14. With respect to ratemaking, for a public utility or natural gas pipeline that continues to have an income tax allowance, any excess or deficient ADIT associated with an asset must continue to be amortized in rates even after the sale or retirement of that asset. This excess or deficient ADIT will continue to be refunded to or recovered from ratepayers based on the schedule that was initially established. Similarly, for ratemaking purposes oil pipelines should keep records of excess and deficient ADIT.

A. In Which Accounts Should Companies Record Amortization of Excess and Deficient ADIT.

15. In the NOI, the Commission sought comment on whether a public utility or natural gas pipeline should record the amortization by recording a reduction to the regulatory asset or regulatory liability account and recording an offsetting entry to Account 407.3 (Regulatory Debits) or Account 407.4 (Regulatory Credits).[37] For oil pipelines, the Commission sought comment on whether this information should be recorded in Account 665 (Unusual or Infrequent Items (Debit)) or Account 645 (Unusual or Infrequent Items (Credit)).[38]

[37] NOI, FERC Stats. & Regs. ¶ 35,582 at P 22.

[38] *Id.*

1. **Comment Summary**

16. Ameren takes issue with the premise of the Commission's question that a separate regulatory liability or asset account is necessary to record excess or deficient ADIT, respectively, arguing that the excess or deficient ADIT should remain in the accounts where they were originally recorded.[39] APPA and AMP, along with Indicated Customers, argue that it would be both appropriate and transparent to record the excess ADIT in the same ADIT accounts (*e.g.,* Accounts 190, 282 and 283) where the original entries for the ADIT assets and ADIT liabilities were established, but believe separate regulatory liability and/or asset accounts would also be appropriate.[40]

17. When separate regulatory liability or assets are used, commenters' viewpoints diverge on the appropriate account to record the offsetting entry. Certain commenters agree with the Commission's initial suggestion.[41] PSEG states that Accounts 407.3 and 407.4 correspond to the appropriate balance sheet account where the excess deferred taxes

[39] Ameren, Comments to NOI, Docket No. RM18-12-000, at 16 (filed May 21, 2018) (Ameren NOI Comments).

[40] APPA and AMP, Comments to NOI, Docket No. RM18-12-000, at 16 (filed May 22, 2018) (APPA and AMP NOI Comments); Indicated Customers, Comments to NOI, Docket No. RM18-12-000, at 14 (filed May 21, 2018) (Indicated Customers NOI Comments).

[41] Berkshire, Comments to NOI, Docket No. RM18-12-000, at 5-6 (filed May 22, 2018) (Berkshire NOI Comments); Consumer Advocates, Comments to NOI, Docket No. RM18-12-000, at 8-10 (filed May 21, 2018) (Consumer Advocates NOI Comments); DEMEC, Comments to NOI, Docket No. RM18-12-000, at 16 (filed May 21, 2018) (DEMEC NOI Comments); PSEG, Comments to NOI, Docket No. RM18-12-000, at 10-11 (filed May 22, 2018) (PSEG NOI Comments); TransCanada, Comments to NOI, Docket No. RM18-12-000, at 25 (filed May 21, 2018) (TransCanada NOI Comments).

reside.[42] Regarding natural gas pipelines, Berkshire asserts that recording the amounts in Account 407.3 or 407.4 will be easier for FERC Form No. 2 users to understand because it will result in similar treatment to other IRS schedule M items and above the line accounting while avoiding the requirement to spread the total year's amortization over each month using the FASB Interpretation No. 18 method.[43]

18. Other commenters believe that either Accounts 407.3 and 407.4 or 410.1 (Provision for deferred income taxes, utility operating income) and 411.1 (Provision for deferred income taxes) are appropriate. Avangrid asserts that Account 407 is consistent with the fact that the excess deferred tax obligation ceased upon tax reform enactment and that the utilities will prospectively amortize a regulatory deferral, rather than a deferred tax liability; however, use of Account 411 is consistent with USofA requirements.[44] EEI and INGAA state that their members' opinions are split between the two accounting options and request that the Commission recognize that both approaches may be appropriate.[45]

[42] PSEG NOI Comments at 10-11.

[43] Berkshire NOI Comments at 5-6.

[44] Avangrid, Comments to NOI, Docket No. RM18-12-000, at 12-13 (May 22, 2018) (Avangrid NOI Comments).

[45] EEI, Comments to NOI, Docket No. RM18-12-000, at 19-20 (filed May 22, 2018) (EEI NOI Comments); INGAA, Comments to NOI, Docket No. RM18-12-000, at 12 (filed June 5, 2018) (INGAA NOI Comments).

19. Many other commenters believe that only Accounts 410.1 and 411.1 are appropriate.[46] New York Transco notes that those accounts were originally used when the regulatory asset or regulatory liability was established.[47]

20. Regarding oil pipelines, AOPL states with respect to regulatory accounting under the USofA, any excess ADIT is eliminated when tax rates change consistent with generally accepted accounting principles, rather than being reduced over time through amortization. AOPL states there is no reason to change either the Commission's accounting rules or current oil pipeline accounting practices; the Commission's ratemaking precedent controls rather than accounting rules for purposes of setting cost-of-service rates.[48]

2. Determination

a. Accounting Guidance

21. We clarify that public utilities and natural gas pipelines should record the amortization of the excess and/or deficient ADIT recorded in Account 254 (Other

[46] Ameren NOI Comments at 16; APPA and AMP NOI Comments at 16; Dominion Energy Gas Pipelines, Comments to NOI, Docket No. RM18-12-000, at 14-15 (filed May 21, 2018) (Dominion Energy Gas Pipelines NOI Comments); Enable Interstate Pipelines, Comments to NOI, Docket No. RM18-12-000, at 39-40 (filed May 21, 2018) (Enable Interstate Pipelines NOI Comments); Indicated Customers, Comments to NOI, Docket No. RM18-12-000, at 10 (filed May 21, 2018) (Indicated Customers NOI Comments); Indicated Local Distribution Companies, Comments to NOI, Docket No. RM18-12-000, at 11 (filed May 22, 2018) (Indicated Local Distribution Companies NOI Comments); New York Transco, Comments to NOI, Docket No. RM18-12-000, at 10 (filed May 22, 2018) (New York Transco NOI Comments).

[47] New York Transco NOI Comments at 10.

[48] AOPL, Comments to NOI, Docket No. RM18-12-000, at 16 (filed May 22, 2018) (AOPL NOI Comments).

Regulatory Assets) and/or Account 182.3 (Other Regulatory Assets) by recording the offsetting entries to Account 410.1 (Provision for Deferred Income Taxes, Utility Operating Income) or Account 411.1 (Provision for Deferred Income Taxes – Credit, Utility Operating Income), as appropriate. As explained below, recording the amortization in Account 410.1 and Account 411.1 is consistent with the instructions for those accounts as detailed in the Commission's regulations and provides more transparency as compared with recording the amounts in Account 407.3 and Account 407.4 because the specific source of the regulatory asset or regulatory liability will be known.

22. The Commission's instructions for Account 182.3 provide in part "[w]hen specific identification of the particular source of a regulatory asset cannot be made . . . account 407.4, regulatory credits, shall be credited."[49] Similarly, the Commission's instructions for Account 254 state in part "[w]hen specific identification of the particular source of the regulatory liability cannot be made . . . account 407.3, regulatory debits, shall be debited."[50]

23. In contrast, Account 410.1 and Account 411.1 are specifically designated for the recordation of ADIT.[51] In this situation where, as a result of a change in tax law or rates,

[49] *See* Definition of Account 182.3, 18 CFR part 101, *Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act*; Definition of Account 182.3, 18 CFR part 201, *Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act.*

[50] *See* Definition of Account 254, 18 CFR part 101, *Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act*; Definition of Account 254, 18 CFR part 201, *Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act.*

[51] *See* Definition of Account 410.1 and 411.1, 18 CFR part 101, *Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the*

excess and/or deficient ADIT have been reclassified to Account 254 and/or Account 182.3, in accordance with the Commission's prior guidance,[52] specific identification of the source of the regulatory liability and/or regulatory asset can be made. Accordingly, the Commission's existing regulations support amortizing the excess and/or deficient ADIT recorded in Account 254 and/or Account 182.3 to Account 410.1 or Account 411.1, as appropriate and consistent with the manner such amounts are reflected in rates.

24. With respect to oil pipelines, deferred tax balances should be adjusted for the effect of changes in tax law or rates in the period the change is enacted in accordance with the USofA for oil pipelines.[53] Specifically, upon the enactment of the Tax Cuts and Jobs Act, oil pipelines should have reduced their ADIT balances to reflect the 21 percent federal income tax rate with offsetting entries to the appropriate income statement account.[54] We believe the current guidance set forth in the USofA is appropriate and will not require oil pipelines to account for excess or deficient ADIT or record the amortization of such amounts. However, to ensure transparency with respect to these ADIT adjustments, oil

Federal Power Act; Definition of Account 410.1 and 411.1, 18 CFR part 201, *Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act.*

[52] *See Accounting for Income Taxes,* Docket No. AI93-5-000, at Item 8 (Apr. 23, 1993).

[53] *See* 18 CFR 352, General Instructions 1-12(b), Accounting for Income Taxes. *See also*, 18 CFR 352, Instructions for Balance Sheet Accounts, 19-5 Current Deferred Income Tax Assets, 45 Accumulated Deferred Income Tax Assets, 59 Deferred Income Tax Liabilities, and 64 Accumulated Deferred Income Tax Liabilities.

[54] *Id*.

pipelines should disclose in the Notes to their Form No. 6 financial statements, the amounts of their ADIT adjustments resulting from the change in the federal corporate income tax rate, supported by a schedule that illustrates the calculation of the revised balances. Because the accounting for the excess and/or deficient ADIT may create differences between oil pipelines' accounting and ratemaking, such differences should also be disclosed in the Notes to their Form No. 6 financial statements, Form No. 6 Page 230, Analysis of Federal Income and Other Taxes Deferred, and Page 700, Annual Cost of Service Based Analysis Schedule.

b. Ratemaking Guidance

25. With respect to public utilities, the appropriate ratemaking treatment will be addressed in the Notice of Proposed Rulemaking (NOPR) we are issuing concurrent with this Policy Statement. In the NOPR, we are proposing to require all public utility transmission providers with transmission rates under an Open Access Transmission Tariff (OATT), a transmission owner tariff, or a rate schedule to revise those rates to account for changes caused by the Tax Cuts and Jobs Act. Natural gas pipelines should continue to file for changes in rates consistent with sections 154.305, 154.312, and 154.313 of the Commission's regulations.[55]

26. For oil pipelines, the current regulatory treatment of excess and/or deficient ADIT amounts is to maintain such amounts separately for rate making purposes only and to amortize them by removing the annual amortization amount from the cost of service in the process of determining an income tax allowance. We will continue the practice of

[55] 18 CFR 154.305, 154.312, 154.313 (2018). Section 154.313 should be used if the filing requests a minor rate change.

amortizing and removing the excess and or deficiency by reducing the allowed return before it is grossed up for income taxes.

B. <u>Whether, and if so how, to address excess ADIT that is removed from the books of public utilities, natural gas pipelines, and oil pipelines after December 31, 2017, as a result of assets being sold or retired.</u>

27. In the NOI, the Commission sought comment on whether, and if so how, it should address excess ADIT that is removed from the books of public utilities, natural gas pipelines, and oil pipelines after December 31, 2017, as a result of assets being sold or retired.[56]

1. <u>Comment Summary</u>

28. Both public utility and natural gas pipeline commenters note that, to date and in response to the last time Congress changed the federal corporate income tax rate, the IRS only has issued guidance on the disposition of excess ADIT in the context of extraordinary retirements.[57] They suggest that the Commission defer addressing excess ADIT that is removed from the books as a result of assets being sold or retired unless and until the IRS has had an opportunity to weigh in on this issue.[58]

[56] NOI, FERC Stats. & Regs. ¶ 35,582 at P 20.

[57] *See* Treas. Reg. 26 CFR § 1.168(i)-3, Treatment of Excess Deferred Income Tax Reserve Upon Disposition of Deregulated Public Utility Property.

[58] Avangrid NOI Comments at 11; EEI NOI Comments at 19; Ameren NOI Comments at 15; EQT Midstream, Comments to NOI, Docket No. RM18-12-000, at 14 (filed May 21, 2018) (EQT Midstream NOI Comments); Indicated Transmission Owners, Comments to NOI, Docket No. RM18-12-000, at 10 (filed May 22, 2018); Dominion Energy Gas Pipelines NOI Comments at 13.

29. Certain public utilities argue that, for companies that properly reflect Average Rate Assumption or the Reverse South Georgia Method and have formula rates that reflect ADIT balances and adjustments thereto, there is no need for the Commission to address excess ADIT that is removed from the books after December 2017 as a result of assets being sold or retired.[59]

30. Similarly, several natural gas pipelines contend that Commission precedent is clear that when assets are sold or transferred as part of a taxable event, the ADIT balance associated with those assets is extinguished; similarly, deferred liabilities resulting from excess ADIT are also extinguished following the retirement of an asset. These pipelines believe that the Commission has provided no basis for departing from these clear rules.[60] These pipelines note that the Commission has stated that "ADIT balances consist of deferred taxes that are intended to be paid at a future time - when the taxes become due. When a taxable event occurs such as the sale of assets . . . taxes are due and the ADIT balances are reduced to zero;" thus, the "ADIT balances that existed prior to the sale no longer exist and are no longer an offset against rate base."[61] These pipelines state the NOI explained that any ADIT associated with assets that are sold are removed from the regulated

[59] Ameren NOI Comments at 14, MISO Transmission Owners, Comments to NOI, Docket No. RM18-12-000, at 14 (filed May 21, 2018).

[60] EQT Midstream NOI Comments at 14; INGAA NOI Comments at 11-12; Tallgrass, Comments to NOI, Docket No. RM18-12-000, at 12-13 (filed May 21, 2018); AOPL NOI Comments at 14-15; Enable Interstate Pipelines, Comments to NOI, Docket No. RM18-12-000, at 40 (filed on May 21, 2018).

[61] *Id.* (citing *Enbridge Pipeline (KPC),* 102 FERC ¶ 61,310, at PP 5, 68 (2003)).

entity's "books because any previously deferred tax effects related to the assets are now triggered as part of the computation of gains or losses associated with the sale (i.e., the deferred taxes are now payable to the IRS)."[62]

31. Eversource and Exelon submit that treatment of ADIT balances is best addressed on a company-specific basis and that companies should be able to either remove the ADIT associated with assets removed from their books or continue to amortize those balances over the remaining amortization period.[63] Indicated Local Distribution Companies suggest that any future sale or retirement event should be decided as part of a pipeline's general rate proceeding.[64]

32. Other commenters urge the Commission to require regulated entities to return any excess ADIT associated with any sold or retired assets. They argue that the Commission should be guided by the principle that all excess ADIT balances were provided by customers and thus customers should be credited with such balances through the combination of a credit to amortization expense and the continued offset to rate base. In support, they assert that when a public utility sells a jurisdictional asset, it will remove from its books the entire ADIT associated with a sold asset, which does not transfer with the asset to the new owner, and retain the entire ADIT for investors. Thus, customers are never credited with the excess

[62] *Id.* (citing NOI, FERC Stats. & Regs. ¶ 35,582 at P 20).

[63] Eversource, Comments to NOI, Docket No. RM18-12-000, at 10 (filed May 22, 2018); Exelon, Comments to NOI, Docket No. RM18-12-000, at 14 (filed May 22, 2018).

[64] Indicated Local Distribution Companies NOI Comments at 9.

or any other part of the ADIT that they have been paying during the useful life of the asset prior to its sale.[65]

33. Indicated Customers note that with regard to the sale of public utility assets for which there is an excess ADIT balance remaining on the books, the 2006 IRS Private Letter Ruling No. PLR-168537-02 prohibits the return to ratepayers of that ADIT and excess ADIT related to the asset that is being sold, because any ADIT and excess ADIT amounts that are on the books for that asset cease to exist as of the date of sale.[66] Notwithstanding, Indicated Customers, and APPA and AMP argue that the impact of not returning both the ADIT and excess ADIT, prior to the sale, and the consequent appropriation of customer-provided capital, should be given consideration in the Commission's evaluation of the application seeking approval of the asset transfer. If the ADIT and excess ADIT are not considered in the transfer transaction, they contend that the selling entity would receive a windfall to the detriment of ratepayers. Further, the acquiring utility could have no offsetting ADIT in its

[65] Consumer Advocates NOI Comments at 8; Indicated Customers NOI Comments at 10-11; DEMEC NOI Comments, Kumar Test. at P 14.

[66] I.R.S. P.L.R., 168537-02 at 9 (May 25, 2006) ("Because [t]axpayer has sold the assets that generated the [accumulated deferred investment tax credit] ADITC, the asset for which regulated depreciation expense is computed is no longer available. Consequently, no portion of the related unamortized ADITC remaining at the date of sale may be returned to ratepayers by amortizing those ADITC amounts over the period [t]axpayer recovers stranded costs from its ratepayers or by decreasing the net loss from the sale of the nuclear generating assets by those ADITC amounts. Additionally, the unamortized [accumulated deferred investment tax credit] and [excess deferred federal income taxes] associated with the sold generating assets ceases to exist at the date of sale."). APPA and AMP argue that this Private Letter Ruling can be read to have no bearing on the flowback of unprotected ADIT balances. APPA and AMP NOI Comments at n. 8.

rate base related to the purchased assets, thereby causing an increase in rates to customers, in addition to the customers' loss of capital advanced to the selling utility.[67]

34. Commenters that believe that the Commission should require ADIT balances be returned to the customers offer several suggestions. APPA and AMP suggest that in the case of a sale or early retirement of public utility assets, the flowback should occur immediately in the formula rate update after the event; otherwise, the flowback should be in the form of a lump-sum payment or credit.[68] Indicated Customers suggest that the Commission should consider deploying remedies it has used in proceedings under FPA section 203, such as establishing an open season for customers to terminate their contracts, a commitment by applicants to protect customers from any adverse rate impacts, rate moratorium or rate reduction.[69] Natural Gas Indicated Shippers suggest that the excess ADIT associated with sold or retired assets should be amortized and returned to the customers in the same manner a pipeline proposes to return excess ADIT due to tax cost changes.[70]

[67] Indicated Customers NOI Comments at 10-11; APPA and AMP NOI Comments at 13-14.

[68] APPA and AMP NOI Comments at 13-14.

[69] Indicated Customers NOI Comments at 11-12 (citing *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, FERC Stats. & Regs. ¶ 31,044 (1996), *order on reconsideration*, 79 FERC ¶ 61,321 (1997)).

[70] Tallgrass Pipelines, Comments to NOI, Docket No. RM18-12-000, at 18 (filed May 22, 2018).

2. Determination

a. Accounting Guidance

35. As discussed above, in 1993, the Chief Accountant issued guidance on how entities must account for the effect of a change in tax law or rates by adjusting its deferred tax liabilities and assets.[71] This guidance remains unchanged, and requires an entity to adjust its deferred tax liabilities and assets for the effect of the change in tax law or rates in the period that the change is enacted.[72] If as a result of action by a regulator, it is probable that the future increase or decrease in taxes payable due to a change in tax law or rates will be recovered from or returned to customers through future rates, an asset or liability shall be recognized in Account 182.3 (Other Regulatory Assets) for deficient ADIT, or Account 254 (Other Regulatory Liabilities) for excess ADIT, as appropriate.[73] Because these deficient ADIT and excess ADIT balances can no longer be characterized as deferred tax amounts to be settled with the IRS, the sale or retirement of any assets as of January 1, 2018 would not automatically reverse these balances as tax timing differences.

36. Accordingly, for public utilities and natural gas pipelines, the excess and/or deficient ADIT recorded in Account 254 and/or Account 182.3 should continue to be recorded in those accounts and amortized to Accounts 410.1 and/or Account 411.1, if those balances are

[71] *See Accounting for Income Taxes,* Docket No. AI93-5-000, at Item 8 (Apr. 23, 1993).

[72] *Id.*

[73] *Id.*

still deemed to be either refundable to or recoverable from ratepayers. If the rate treatment of those balances is instead disallowed, then those amounts shall be written off to Account 421 (Miscellaneous Non-Operating Income) or Account 426.5 (Other Deductions), as appropriate, in the year of the disallowance.[74]

37. We clarify that, for public utilities and natural gas pipelines, the balances of excess and deficient ADIT recorded in Account 254 and Account 182.3, respectively, continue to exist as regulatory liabilities and assets after an asset sale, in cases for which the excess and deficient ADIT do not transfer to the purchaser of the plant asset. Similarly, we clarify that public utilities and natural gas companies should continue to account for excess and deficient ADIT related to retirements as regulatory liabilities and assets.

38. We acknowledge that numerous current and deferred tax accounts as well as other accounts may be affected by reversals of ADIT account balances recorded on the books of public utilities and natural gas companies subject to the Commission's jurisdiction. Thus, in order to provide transparency regarding the accounting and rate treatment of amounts removed from the ADIT accounts, we clarify that public utilities and natural gas pipelines should disclose in their FERC annual financial filings within the Notes to the Financial Statements: (1) the FERC accounts affected; (2) how any ADIT accounts were re-measured in the determination of the excess or deficient ADIT amounts in Accounts 182.3

[74] *See* Definitions of Account 182.3 and Account 254, 18 CFR part 101, *Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act*; Definitions of Account 182.3 and Account 254, 18 CFR part 201, *Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act.*

and 254; (3) the related amounts associated with the reversal and elimination of ADIT balances in those accounts; (4) the amount of excess and deficient ADIT that is protected and unprotected; (5) the accounts to which the excess or deficient ADIT will be amortized; and (6) the amortization period of the excess and deficient ADIT to be returned or recovered through rates for both protected and unprotected ADIT.[75] Disclosures should also summarize the manner by which excess and deficient will be included in rates by rate jurisdiction.

39. As for oil pipelines, as discussed above, ADIT balances will be reduced immediately by the full amount of the excess or deficient tax reserve in line with the USofA for oil pipelines outlined in General Instruction 1-12.[76]

b. Ratemaking Guidance

40. The Commission has previously found that the sale or retirement of an asset with an ADIT balance is usually deemed a taxable event under IRS rules, and, as such, the ADIT balance is extinguished as the deferred taxes then become payable to the appropriate government authorities, and there is no longer an ADIT balance to "return" to customers.[77]

[75] Public utilities should include this information in FERC Form No. 1 or 1-A and natural gas pipelines should include this information in FERC Form No. 2 or 2-A.

[76] General Instructions 1-12, *Accounting for Income Taxes*, 18 CFR part 352.

[77] The Commission has found that master limited partnerships that were no longer entitled to an income tax allowance were not required to return any remaining ADIT balances. *Inquiry Regarding the Commission's Policy for Recovery of Income Tax Costs,* 162 FERC ¶ 61,227, *order on reh'g*, 164 FERC ¶ 61,030 (2018) (Revised Income Tax Policy Statement Order on Rehearing). However, as relevant here, the Commission found that "[t]here is a critical distinction between adjustments to amortize excess or deficient ADIT to be included in future rates to account for changes in income tax rates, as opposed

However, we believe that excess or deficient ADIT associated with post-December 31, 2017, asset dispositions and retirements should be treated differently for ratemaking purposes. For these assets, there are two associated balances: (1) the ADIT balance based on the 21 percent tax rate that will be owed to the IRS and (2) deficient ADIT or excess ADIT balances resulting from the reduced tax liability that will not be payable to the IRS upon the sale or retirement of the asset. While the ADIT balance that needs to be settled with the IRS would be extinguished following a sale, the deficient ADIT or excess ADIT balances is more reflective of a regulatory liability or asset, and no longer reflects deferred taxes that are still to be settled with the IRS and need not be extinguished.

41. Additionally, we note that the rationale for continuing to amortize deficient ADIT or excess ADIT balances in rates upon sales or retirements of assets is substantively similar to the rationale for amortizing excess ADIT in rates for assets that have not been sold or retired. The difference is that for a sale or retirement, ADIT based on a 21 percent tax rate will be settled with the IRS immediately, while for an asset that is not sold or retired, the ADIT will be settled with the IRS over the remaining life of the asset as it depreciates. In other words, the difference between the ADIT for assets that are sold or retired and ADIT for assets that are not sold or retired is the timing of when companies will settle the 21

to a complete elimination of the income tax allowance. When income tax rates are merely reduced and an income tax allowance remains in *future* cost of service, it is appropriate to credit any excess in ADIT in the *future* cost of service." Revised Income Tax Policy Statement Order on Rehearing, 164 FERC ¶ 61,030 at P 20. Thus, in the case of retired or sold assets of regulated entities that continue to have an income tax allowance (and in the case of all regulated entities with excess and deficient ADIT), it is appropriate to credit any excess in ADIT in the future cost of service.

percent of ADIT with the IRS. In both scenarios, there is excess ADIT based on the 14 percent previously collected from the customers that will no longer be payable to the IRS.

42. While some commenters suggest that continuing to amortize excess or deficient ADIT following a sale or retirement would constitute a normalization violation based on certain IRS private letter rulings, the Commission notes that the IRS established a rulemaking proceeding and reversed its positions made in the PLR referenced by the commenters.[78] Current IRS regulations speak specifically to the normalization requirements for sales and retirements as a result of the Tax Reform Act of 1986.[79] These regulations permit the amortization of protected excess and/or deficient ADIT even in the event that the underlying asset associated with the ADIT has been sold or retired.[80] That is, the selling jurisdictional entity can continue to amortize excess ADIT in rates after the sale without violating the IRS' normalization requirements. The only limitation imposed by the IRS is

[78] *See Application of Normalization Accounting Rules to Balances of Excess Deferred Income Taxes and Accumulated Deferred Investment Tax Credits of Public Utilities Whose Assets Cease To Be Public Utility Property*, 73 FR 14,934 (Mar. 20, 2008); *Application of Normalization Accounting Rules to Balances of Excess Deferred Income Taxes and Accumulated Deferred Investment Tax Credits of Public Utilities Whose Assets Cease to Be Public Utility Property*, 70 FR 75,762 (Dec. 21, 2005) (notice of proposed rulemaking, notice of public hearing, and withdrawal of previous proposed regulations).

[79] 26 CFR 1.168(i)-3 (2018). This section of the IRS code does not apply to ordinary retirements within the meaning of 26 CFR 1.167(a) –11(d)(3)(ii) of the internal revenue regulations, and such retirements are excluded from this policy statement.

[80] *Id.*

that the timing of the amortization must be similar to protected excess and/or deficient ADIT for which the underlying asset has not been sold or retired.[81]

43. Consistent with the above discussion, oil pipelines should continue maintaining excess and/or deficient ADIT within the appropriate ADIT accounts for ratemaking purposes. When jurisdictional assets are retired or sold the oil pipeline should continue to amortize any excess and/or deficient amounts associated with those assets as part of the process of determining an income tax allowance within the rate making process, or seek prior Commission approval to do otherwise.

C. <u>Conclusion</u>

44. We adopt the policies set forth herein regarding the treatment of ADIT for public utilities, natural gas pipelines and oil pipelines. Above, we state our policy regarding the treatment of ADIT for both accounting and ratemaking purposes as to Commission-jurisdictional public utilities, natural gas pipelines and oil pipelines, in light of the Tax Cuts and Jobs Act of 2017 and also address the accounting and ratemaking treatment of ADIT following the sale or retirement of an asset. We expect such regulated entities to follow these policies absent prior Commission approval to use a different treatment. We further note that if a regulated entity determines that its unique circumstances merit a different treatment of ADIT, such an entity is free to request such treatment at any time.

[81] *Id.*

III. Document Availability

48. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

49. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

50. User assistance is available for eLibrary and the FERC's website during normal business hours from FERC Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

IV. Effective Date

51. This Policy Statement will become effective **[date of publication in the *Federal Register*]**.

By the Commission. Commissioner McIntyre is not voting on this order.

(S E A L)

Nathaniel J. Davis, Sr.,

Deputy Secretary.

Note: Appendix A will not be published in the Federal Register.

Appendix A – List of Commenters to NOI

Short Name	Commenter
AEP	American Electric Power Service Corporation
Ameren	Ameren Services Company on behalf of Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois, and Ameren Transmission Company of Illinois
AOPL	Association of Oil Pipe Lines
APGA	American Public Gas Association
APPA and AMP	American Public Power Association and American Municipal Power, Inc.
Avangrid	Avangrid Networks, Inc.
Berkshire	Berkshire Hathaway Energy Pipeline Group
Boardwalk	Boardwalk Pipeline Partners LP
CAPP	Canadian Association of Petroleum Producers
Consumer Advocates	Office of the Attorney General of the Commonwealth of Massachusetts; the Ohio Consumers' Counsel; the Maryland Office of People's Counsel; the Nevada Bureau of Consumer Protection; the Delaware Division of the Public Advocate; the Pennsylvania Office of Consumer Advocate; the Citizens Utility Board of Wisconsin; and the Indiana Office of Utility Consumer Counselor
DEMEC	Delaware Municipal Electric Corporation, Inc.
Dominion Energy Gas Pipelines	Dominion Energy Transmission, Inc.; Dominion Energy Carolina Gas Transmission, LLC; Dominion Energy Quester Pipeline, LLC; Dominion Energy Overthrust Pipeline, LLC; and Questar Southern Trails Pipeline Company

EEI	Edison Electric Institute
Enable Interstate Pipelines	Enable Mississippi River Transmission, LLC and Enable Gas Transmission, LLC
Enbridge and Spectra	Enbridge Energy Partners, L.P. and Spectra Energy Partners, LP
EQT Midstream	EQT Midstream Partners, LP
Eversource	Eversource Energy Service Company
Exelon	Exelon Corporation
Indicated Customers	Central Electric Power Cooperative, Inc., North Carolina Electric Membership Corporation, Southern Maryland Electric Cooperative, Inc., and the New Jersey Division of Rate Counsel
Indicated Local Distribution Companies	Atmos Energy Corporation; the City of Charlottesville, Virginia; the City of Richmond, Virginia; the Easton Utilities Commission; Exelon Corporation; and Washington Gas Light Company
Indicated Transmission Owners	American Electric Power Service Corporation; Dominion Energy Services, Inc., on behalf of Virginia Electric and Power Company d/b/a Dominion Energy Virginia; Duquesne Light Company; Exelon Corporation; FirstEnergy Service Company, on behalf of American Transmission Systems, Incorporated; Jersey Central Power & Light Company; Mid-Atlantic Interstate Transmission, LLC; West Penn Power Company; The Potomac Edison Company; Monongahela Power Company; and PPL Electric Utilities Corp.
INGAA	Interstate Natural Gas Association of America
ITC Great Plains	ITC Great Plains, LLC
Kentucky Municipals	Frankfort Plant Board of Frankfort, Kentucky; Barbourville Utility Commission of the City of Barbourville, City; Utilities Commission of the City of Corbin; and the Cities of Bardwell, Berea, Falmouth, Madisonville, and Providence, Kentucky

Kinder Morgan Entities	Natural Gas Pipeline Company of America LLC; Tennessee Gas Pipeline Company, L.L.C.; Southern Natural Gas Company, L.L.C.; Colorado Interstate Gas Company, L.L.C.; Wyoming Interstate Company, L.L.C.; El Paso Natural Gas Company, L.L.C.; Mojave Pipeline Company, L.L.C.; Bear Creek Storage Company, L.L.C.; Cheyenne Plains Gas Pipeline Company, L.L.C.; Elba Express Company, L.L.C.; Kinder Morgan Louisiana Pipeline LLC; Southern LNG Company, L.L.C.; and TransColorado Gas Transmission Company LLC
Kinder Morgan Subsidiaries	SFPP, L.P.; Calnev Pipe Line, LLC; and Kinder Morgan Cochin, LLC
MISO Transmission Owners	Ameren Services Company, as agent for Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois and Ameren Transmission Company of Illinois; American Transmission Company LLC; Central Minnesota Municipal Power Agency; City Water, Light & Power (Springfield, IL); Cleco Power LLC; Cooperative Energy; Dairyland Power Cooperative; Duke Energy Business Services, LLC for Duke Energy Indiana, LLC; East Texas Electric Cooperative; Entergy Arkansas, Inc.; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy New Orleans, LLC; Entergy Texas, Inc.; Great River Energy; Indiana Municipal Power Agency; Indianapolis Power & Light Company; International Transmission Company d/b/a ITC*Transmission*; ITC Midwest LLC; Lafayette Utilities System; Michigan Electric Transmission Company, LLC; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Missouri River Energy Services; Montana-Dakota Utilities Co.; Northern Indiana Public Service Company LLC; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Prairie Power Inc.; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); Southern Minnesota Municipal Power Agency; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc.

National Grid	National Grid USA
Natural Gas Indicated Shippers	Aera Energy, LLC; Anadarko Energy Services Company; Apache Corporation; BP Energy Company; ConocoPhillips Company; Hess Corporation; Occidental Energy Marketing, Inc.; Petrohawk Energy Corporation; and XTO Energy, Inc.
New York Transco	New York Transco LLC
Oklahoma Attorney General	Mike Hunter, Oklahoma Attorney General
PJM	PJM Interconnection, L.L.C.
Plains	Plains Pipeline, L.P.
Process Gas and American Forest and Paper	Process Gas Consumers Group and American Forest and Paper Association
PSEG	Public Service Electric and Gas Company
Tallgrass Pipelines	Trailblazer Pipeline Company LLC; Tallgrass Interstate Gas Transmission, LLC; and Rockies Express Pipeline LLC
TAPS	Transmission Access Policy Study Group
TransCanada	TransCanada Corporation
United Airlines Petitioners	United Airlines, Inc.; American Airlines, Inc.; Delta Air Lines, Inc.; Southwest Airlines, Co.; BP West Coast Products LLC; ExxonMobil Oil Corporation; Chevron Products Company; HollyFrontier Refining & Marketing LLC; Valero Marketing and Supply Company; Airlines for America; and the National Propane Gas Association
Williams	Williams Companies, Inc.

TAX SHARING AGREEMENT

AGREEMENT made as of September 10, 1985, among Concord Electric Company a New Hampshire corporation, Exeter & Hampton Electric Company a New Hampshire corporation, UNITIL Service Corp., a New Hampshire corporation, and UNITIL Power Corp., a New Hampshire corporation and UNITIL Corporation ("UNITIL"), a New Hampshire corporation ("AFFILIATE" companies or, collectively, the "AFFILIATES"). Whenever it is intended to include UNITIL in the context of the affiliated group, the term "CONSOLIDATED AFFILIATE" or "CONSOLIDATED AFFILIATES" may be used, and when reference is to the affiliated group as a collective tax paying unit the term "Group" may be used.

WHEREAS, UNITIL owns at least 80 percent of the issued and outstanding shares of each class of voting common stock of each of the AFFILIATES: each of the CONSOLIDATED AFFILIATES is a member of an affiliated group within the meaning of section 1504 of the Internal Revenue Code of 1954, as amended (the "Code"), of which UNITIL is the common parent corporation; and UNITIL proposes to include each of the AFFILIATES in filing a consolidated income tax return for the calendar year 1985;

NOW, THEREFORE, UNITIL and the AFFILIATES agree as follows:

1. Consolidated Return Election. If at any time and from time to time UNITIL so elects, each of the AFFILIATES will join in the filing of a consolidated Federal income tax return for the calendar year 1985 and for any subsequent period for which the Group is required or permitted to file such a return. UNITIL and its affiliates agree to file such consents, elections and other documents and to take such other action as may be necessary or appropriate to carry out the purposes of this Section 1. Any period for which any of the AFFILIATES is included in a consolidated Federal

income tax return filed by UNITIL is referred to in this Agreement as a "Consolidated Return Year".

2. <u>AFFILIATES' Liability to UNITIL for Consolidated Return Year</u>. Prior to the filing of each consolidated return by UNITIL each of the AFFILIATES included therein shall pay to UNITIL the amount, if any, of the Federal income tax for which the AFFILIATES would have been liable for that year, computed in accordance with Treasury Regulations, section 1.1552-1(a)(2)(ii) as though that AFFILIATE had filed a separate return for such year, giving effect to any net operating loss carryovers, capital loss carryovers, investment tax credit carryovers, foreign tax credit carryovers or other similar items, incurred by that AFFILIATE for any period ending on or before the date of this Agreement.

The foregoing allocation of Federal income tax liability is being made in accordance with Treasury Regulations, sections 1.1552-1(a)(2) and 1.1502-33 (d)(2)(ii), and no amount shall be allocated to any CONSOLIDATED AFFILIATE in excess of the amount permitted under Treasury Regulations, section 1.1502-33(d)(2)(ii). Accordingly, after taking into account the allocable portion of the Group's Federal income tax liability, no amount shall be allocated to any CONSOLIDATED AFFILIATE in excess of the amount permitted in accordance with Treasury Regulations, section 1.1502-33(d)(2)(ii).

3. UNITIL Liability to Each Affiliate for Consolidated Return Year. If for any Consolidated Return Year, any AFFILIATE included in the consolidated return filed by UNITIL for such year has available a net operating loss, capital loss, foreign tax credit, investment tax credit or similar items (computed by taking into account carryovers of such items from periods ending on or before the date of this Agreement) that reduces the consolidated tax liability of the Group below the amount that would have been payable if that AFFILIATE did not have such item available, UNITIL shall pay the amount of the reduction attributable to such AFFILIATE prior to the filing of the consolidated return for such year.

The amount of the reduction shall be equal to a portion of the excess of (i) the total of the separate return tax liabilities of each of the CONSOLIDATED AFFILIATES computed in accordance with Section 2 of this Agreement, over (ii) the Federal income tax liability of the Group for the year. The portion of such reduction attributable to an AFFILIATE shall be computed by multiplying the total reduction by a fraction, the numerator of which is the value of the tax benefits contributed by the AFFILIATE to the Group and the denominator of which is the value of the total value of such benefits contributed by all CONSOLIDATED AFFILIATES during the year.

For purposes of the foregoing paragraph a deduction or credit generated by a CONSOLIDATED AFFILIATE which is in excess of the amount required to eliminate its separate tax return liability but which is utilized in the computation of the Federal income tax liability of the Group shall be deemed to be a tax benefit contributed by the CONSOLIDATED AFFILIATE to the Group. The value of a deduction which constitutes such a benefit shall be determined by applying the current corporate income tax rate, presently 46 percent, to the amount for the deduction. The value of a credit that constitutes such a benefit shall be the tax savings, currently 100 percent thereof. The value of capital losses used to offset capital gains shall be computed at the then current rate appliable to capital gains for corporations.

4. Payment of Estimated Taxes. Prior to the paying and filing of estimated consolidated tax declaration by UNITIL, each of the AFFILIATES included in such estimated tax declaration shall pay to UNITIL the amount, if any, of the estimated Federal income tax for which the AFFILIATE would have been liable for that year, computed as though that AFFILIATE had filed a separate estimated tax declaration for such year.

5. Tax Adjustments. In the event of any adjustments to the consolidated tax return as filed (by reason of an amended return, a claim for refund or an audit by the Internal Revenue Service), the liability, if any, of each of the AFFILIATES under Sections 2, 3, and 4 shall be redetermined to give effect to any such adjustment as if it had been made as part of the original computation of tax liability, and payments between UNITIL and the appropriate AFFILIATES shall be made within 120 days after any such payments are made or refunds are received, or, in the case of contested proceedings, within 120 days after a final determination of the contest.

interest and penalties, if any, attributable to such an adjustment shall be paid by each AFFILIATE to UNITIL in proportion to the increase in such AFFILIATE'S separate return tax liability that is required to be paid to UNITIL, as computed under Section 2.

6. Subsidiaries of Affiliates. If at any time, any of the AFFILIATES acquire or creates one or more subsidiary corporations that are includable corporations of the Group, they shall be subject to this Agreement and all references to the AFFILIATES herein shall be interpreted to include such subsidiaries as a group.

7. Successors. This Agreement shall be binding on and inure to the benefit of any successor, by merger, acquisition of assets or otherwise, to any of the parties hereto (including but not limited to any successor of UNITIL or any of the AFFILIATES succeeding to the tax attributes of such corporation under section 381 of the Code) to the same extent as if such successor had been an original party to this Agreement.

8. Affiliates' Liability for Separate Return Years. If any of the AFFILIATES leaves the Group and files separate Federal income tax returns, within 120 days of the end of each of the first fifteen taxable years for which it files such returns, it shall pay to UNITIL the excess, if any, of (A) Federal income tax that such AFFILIATE would have paid for such year (on a separate return basis giving effect to its net operating loss carryovers) if it never had been a

member of the Group, over (b) the amount of Federal income tax such AFFILIATE has actually paid or will actually pay for such years.

9. Examples of Calculations. Attached hereto and made part hereof, as "Appendix A To Tax Sharing Agreement By And Between UNITIL Corporation And Its Affiliated Companies", are illustrative examples of the matters contained herein.

IN WITNESS WHEREOF, the duly authorized repsesentatives of the parties hereto have set their hands this tenth day of September, 1985.

UNITIL CORPORATION

By Michael J Dalton
Its President

EXETER & HAMPTON ELECTRIC COMPANY

By Michael J Dalton
Its President

CONCORD ELECTRIC COMPANY

By [illegible]
Its President

UNITIL POWER CORP.

By Michael J Dalton
Its President

UNITIL SERVICE CORP.

By Peter J. Stulgis
Its President

APPENDIX A TO TAX SHARING AGREEMENT
BY AND BETWEEN UNITIL CORPORATION AND ITS
AFFILIATED COMPANIES

The allocation agreement follows the Internal Revenue Service regulations for "basic" and "supplemental" allocation of consolidated return liability and benefits.

The "basic" method used to allocate UNITIL'S liability shown on the consolidated return is provided by Internal Revenue Code section 1552(a) and provides for allocation based on the amount of tax liability calculated on a separate return basis.

The "supplemental" method provides that the tax savings of credits and deductions in excess of the amount of an individual company can use, but which can be used in consolidations, is allocated among the members supplying the savings and the benefiting members reimburse them.

For example, assume that a three member group has consolidated taxable income and consolidated tax liability of \$200,000 and \$100,000 respectively. The individual members, A, B, and C have separate return taxable income (loss) of \$150,000 \$100,000 and \$(50,000) and the individual members have separate return liabilities of \$75,000, \$50,000 and none, respectively. (Loss members are deemed to have a zero tax liability). Under the proposed method, the individual tax liability and benefit is allocated as follows:

Member	A	B	C
Taxable income (loss)	\$150,000	\$100,000	\$(50,000)
Separate Tax Liability	75,000	50,000	none
Percent of Total (\$125,000)	60%	40%	0%
Consolidated Tax Allocation	60,000	40,000	none
Separate Tax Liability	75,000	50,000	0
Less Conslidated Tax	60,000	40,000	0
	15,000	10,000	0
	100%	100%	
Supplemental Allocation	15,000	10,000	0
Benefits paid to C	\$(15,000)	\$(10,000)	\$(25,000)

Regulation 1.1502-33(d) provides the "supplemental" method of allocating tax liability in order to permit members to receive reimbursement for contributing tax deductions or credits to the group. The method adopted by the Company and outlined at Regulation 1.1502-33(2)(ii) provides for immediate reimbursement for the tax year involved. The steps are as follows:

(1) Tax liability is allocated to the members by the basic method outlined above.

(2) Each member with a separate company tax will be allocated 100% of the excess of its separate return liability over its share of the consolidated liability under step (1).

(3) The amounts allocated to benefiting members under Step 2 are credited to the members supplying the capital losses, deductions, credits, or other items to which the savings are attributable. for this purpose, an amount generated by a member which is in excess of the amount required to eliminate its own separate return tax liability and which is utilized in the computation of the Federal income tax liability of the group shall be deemed to be a tax benefit contributed by the member to the group.

In some years the Step 2 savings to be credited may be less than the total tax savings items available for use. In such a case, the savings shall be attributed to tax savings items in the order that they are used on the consolidated return and in an amount equal to the savings actually realized.

Under this method, capital losses would normally be used first to the extent there are capital gains, since these items are netted in order to reach income, and are used before any deductions or credits are taken into account. The value of the capital loss would be the current rate of tax for capital gain income of the loss. The next item to be used would be deductions resulting in a current year operating loss, and these would be valued at the marginal rate of tax on the income they offset. This is normally 46 percent under current law, but would be less for income under $100,000, which falls in to the graduated tax brackets Under Reg. 1.1502-33(d)(2), the amount of each graduated rate bracket is apportioned equally by dividing that amount by the number of corporations that were members of the group. Additionally, an alternative is to allocate the amount of each graduated rate bracket based on a election made by each of the companies' and included with that year's tax return. Operating loss carryovers would be used next, and finally credits would be used. Credits will be valued at 100 percent, since they result in dollar for dollar savings. Where the total amount of an item is not used, the savings will be allocated to each member in proportion to his share of the total of that benefit available from all members of the consolidated group.

(4) Benefiting members will reimburse the other members prior to the filing of the consolidated tax return..

A more complicated situation is presented when there are several loss companies. Assume that the facts are the same as above except that there are three loss companies: C, D and E with the following tax savings items:

	C	D	E
Capital Loss	0	5,000	0
Current Operating Loss	5,000	0	3,000
Operating Loss Carryover	0	10,000	0
Credits	4,000	8,000	4,000

Allocation of the $25,000 benefit from Step (2) would proceed as follows:

	C	D	E	Remaining Benefit
Captial Gains @ 28%	0	1,400	0	23,600
Current Operating Loss Offsetting 46% Income	2,300	0	1,380	19,920
Operating Loss Carryover Offsetting 46% Income		4,600		15,320
Credits @ 100% *(proportionate)*	3,830	7,660	3,830	0
Total Allocated	6,130	13,660	5,210	0

Thus companies A and B would reimburse C, D and E for the above amounts. There will be credit carryovers for C, D, and E of $170, $340, and $170, respectively.

Separate Return Liability

The Allocations and reimbursements outlined above use the concept of a "separate return tax liability" as a starting point for allocations. This liability is the amount which a member of the affiliated group would pay if it filed a separate return. It is calculated in three basic steps.

(1) The rules for consolidated return deferred accounting, inventory ajustments, basis determination, basis adjustments, excess losses, earnings and profits, and obligations of members must be applied.

(2) Intercompany dividends are eliminated and no dividend received or paid deduction is allowed on intercompany

dividends.

(3) Adjustments are made for specific items used in the consolidated return which must be divided by some equitable method among the members.

The third step is the subject of this part of the Appendix. Two different approaches may be taken for the apportionment of the limits, deductions, and exemptions used to reach tax liability.

It is recognized that each company is a part of an affiliated group, and that all credits, deductions and limitations must be apportioned in some equitable manner.

Specific Apportionments

(1) Carryovers. On a consolidated basis, items such as operating losses, capital losses, and contributions will be used first from the current year and then carried forward from the oldest year forward until exhausted. It is the intention of the Tax Sharing Agreement, for allocation and reimbursement purposes, that a member shall use its own carryovers first before it is required to reimburse another member for use of its carryover in consolidation, without regard for the fact that the tax regulations for consolidated returns may require a different order.

(2) Contribution Deduction. The amount of the contribution deduction is limited to 10% of consolidated taxable income. Thus the amount allowable may exceed the actual contributions. In order to avoid having a consolidated contribution carryover which is not owned by a member, each member agrees that its deduction be limited to its proportionate share on a separate return basis of the consolidated contribution deduction in a given year, rather than 10% of its separate return income, and that any contribution in excess of such amount be treated as its own carryover.

If the consolidated deduction is greater than the separate deductions of the profitable members (thus permitting a deduction for contributions of a loss member) the excess allowable deduction will be allocated to the loss members in proportion to the excess allowable over their available contributions.

Contribution Illustration

Example A

	A	B	C	Consolidated
Income before contributions	12,000	100	(5,600)	6,500
Contributions-current	400	25	100	
-carryover	300	25		
-available	700	50	100	
10% limit				650
Allowable on SR basis	1,200	10		
Allowable by agreement	644	6		
Carryover by agreement				
-current	-0-	19	100	
-prior	56	25		
Taxable income	11,356	94	(5,600)	5,850

Example B

	A	B	C	Consolidated
Income before contributions	12,000	(100)	(5,400)	6,500
Contributions-current only	200	50	200	
10% limit				650
Available on SR basis	200			200
Excess deduction allowable				250
Allocation by agreement		50	200	
Carryover by agreement		50	200	
Taxable income	11,800	(150)	(5,600)	6,050

(3) Tax Brackets. The members agree that the brackets will first be applied equally to the members with ordinary income. If the allocated amount exceeds income, the excess can be reapplied equally to the other members with remaining income.

(4) I.T.C. Limitation. The limitation on 100% utilization of investment tax credit provided by Internal Revenue Code S46(a)(3), currently $25,000, will be allocated equally among the members with tax liability and available credits, with any excess to be allocated equally to those with remaining liability and credits.

(5) I.T.C. Limit For Used Property. The limitation on used property cost deemed eligible for investment credit, currently $125,000, will be allocated equally among the companies that have used property acquisitions with a ten year recovery life in any year. If a member is unable to utilize all of its allocated amount, the excess will be allocated proportionately to the members with used property acquisitions in excess of their allocated share. If there are insufficient ten year recovery life assets, the remainder will be allocated to five year recovery life assets in a similar manner. Likewise, if there are not enough ten and five year recovery life assets, the remainder of the $100,000 limitation will be allocated equally to members having three year recovery life used property additions.

(6) Future Developments. Any credits, deductions, or other items established by future legislation will be allocated in a manner consistent with the above methods.

The foregoing examples are for illustrative purposes and are not intended to cover all possible situations that may arise.

Unitil Energy Systems, Inc.
Excess Accumulated Deferred Income Tax (ADIT)
At December 31, 2020

	(a)	(b)
COL/LN	**Description**	**Excess ADIT at 12/31/2020**
1	Utility Plant Differences	$ (16,742,983)
2	Contributions In Aid of Construction (CIAC)	68,713
3	SFAS 106 - PBOP	1,111,344
4	SFAS 87 - Pensions	(803,338)
5	Debt Discount Expense	(1,547)
6	Bad Debt	33,810
7	Prepaid Property Tax	(207,651)
8	Deferred Rate Case & Restructuring	(68,270)
9	DER Investment	(15,527)
10	Indenture Costs	(46,159)
11	FAS 109 Reg Asset	70,262
12	**Total Excess ADIT**	**$ (16,601,346)**

DE 21-030
Exhibit JAG-6
Page 1 of 1

Unitil Energy Systems, Inc.
Excess Accumulated Deferred Income Tax ARAM Schedule

	(a)	(b)	(c)	(d)	(e)
COL/LN	YEAR	AMOUNT	GROSS-UP	REGULATORY LIABILITY	SOURCE
1	2018	(582,653)	(216,410)	(799,064)	PowerTax Report 257
2	2019	(652,910)	(242,505)	(895,415)	PowerTax Report 257
3	2020	(692,793)	(257,319)	(950,111)	PowerTax Report 257
4	2021	(729,021)	(270,774)	(999,795)	PowerTax Report 257
5	2022	(760,108)	(282,321)	(1,042,429)	PowerTax Report 257
6	2023	(758,595)	(281,759)	(1,040,353)	PowerTax Report 257
7	2024	(768,057)	(285,273)	(1,053,330)	PowerTax Report 257
8	2025	(791,099)	(293,832)	(1,084,930)	PowerTax Report 257
9	2026	(814,832)	(302,647)	(1,117,478)	PowerTax Report 257
10	2027	(839,276)	(311,726)	(1,151,002)	PowerTax Report 257
11	2028	(864,455)	(321,078)	(1,185,533)	PowerTax Report 257
12	2029	(890,388)	(330,710)	(1,221,099)	PowerTax Report 257
13	2030	(872,581)	(324,096)	(1,196,677)	PowerTax Report 257
14	2031	(855,129)	(317,614)	(1,172,743)	PowerTax Report 257
15	2032	(838,026)	(311,262)	(1,149,288)	PowerTax Report 257
16	2033	(821,266)	(305,036)	(1,126,302)	PowerTax Report 257
17	2034	(804,841)	(298,936)	(1,103,776)	PowerTax Report 257
18	2035	(788,744)	(292,957)	(1,081,701)	PowerTax Report 257
19	2036	(772,969)	(287,098)	(1,060,067)	PowerTax Report 257
20	2037	(757,510)	(281,356)	(1,038,865)	PowerTax Report 257
21	2038	(742,359)	(275,729)	(1,018,088)	PowerTax Report 257
22	2039	(203,737)	(75,672)	(279,409)	PowerTax Report 257
23	TOTAL	$ (16,601,346)	$ (6,166,110)	$ (22,767,457)	

[THIS PAGE INTENTIONALLY LEFT BLANK]

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY

OF

RONALD J. AMEN

EXHIBIT RJA-1

New Hampshire Public Utilities Commission

Docket No. DE 21-030

TABLE OF CONTENTS

<u>SCHEDULES</u>

Appendix A	Background and Work Experience
Schedule RJA-2	Summary of Allocated Cost of Service Study Results
Schedule RJA-3	Proposed Revenue Allocation by Class
Schedule RJA-4	ACOSS Unit Cost Report
Schedule RJA-5	Summary of ACOSS External Allocation Factors
Schedule RJA-6	Description of ACOSS Functionalization and Classification of Accounts
Schedule RJA-7	Minimum System Study
Schedule RJA-8	Marginal Cost of Service Study

I. INTRODUCTION

Q. Please state your name and business address.

A. Ronald J. Amen. My business address is 10 Hospital Center Commons, Suite 400, Hilton Head, SC 29926-2849.

Q. By whom and in what capacity are you employed?

A. I am a Managing Partner with Atrium Economics, LLC ("Atrium"). Atrium is a management consulting and financial advisory firm focused on the North American energy industry.

Q. Please describe Atrium's business activities.

A. Atrium offers a complete array of rate case support services including advisory and expert witness services relating to revenue recovery, pricing, integration of technology, distributed generation, and affiliate transactions. We have extensive experience in rate case management; revenue requirement development; allocated embedded and marginal cost of service studies; rate design and rate alignment; and affiliate and shared services.

We have appeared as expert witnesses on behalf of energy utilities in regulatory proceedings across North America supporting financial, economic, and technical studies before numerous state and provincial regulatory bodies, as well as before the Federal Energy Regulatory Commission ("FERC"). The Atrium Team has extensive background and experience both in management positions inside electric and gas utilities and as advisors to our clients.

Q. On whose behalf are you testifying?

A. Unitil Energy Systems, Inc. ("UES" or "the Company") retained Atrium to conduct the allocated class cost of service study (ACOSS); the marginal class cost of service study (MCOSS); the revenue apportionment and revenue targets by class; the rate design for existing rate classes; Light Emitting Diode ("LED") rates; and Time Of Use ("TOU") rates for the domestic class and for Electric Vehicle ("EV") charging. I am supporting the Company's ACOSS, MCOSS, and revenue apportionment and revenue targets by class. My colleague John Taylor is supporting the Company's rate design proposals, including new LED rates, the Domestic TOU rate and TOU rates for EV charging.

Q. What has been the nature of your work in the utility consulting field?

A. I have over 40 years of experience in the utility industry, the last 23 years of which have been in the field of utility management and economic consulting. I have advised and assisted utility management, industry trade organizations, and large energy users in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, resource planning issues, strategic business planning, merger and acquisition analysis, organizational restructuring, new product and service development, and load research studies. I have prepared and presented expert testimony before numerous utility regulatory bodies across North America and have spoken on utility industry issues and activities dealing with the pricing and marketing of gas utility services, gas and electric resource planning and evaluation, and utility infrastructure replacement.

Further background information summarizing my work experience, presentation of expert testimony, and other industry-related activities is included in Appendix A.

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("Commission")?

A. No.

Q. Please summarize the topics addressed in your testimony.

A. My testimony discusses the role of the ACOSS and MCOSS in providing guidance toward designing economically efficient rates. Cost causation is a fundamental principle for these studies. Understanding cost causation requires an in-depth understanding of the planning and operation of the utility system, as well as the basic economics of the electric system components.

The ACOSS and MCOSS prepared for this case reveal how UES incurs costs to serve its various classes of customers. The single most important conclusion from the cost studies is that in order to collect the costs from customers who cause the costs to be incurred, rates must better reflect the nature of these costs.

II. COST OF SERVICE STUDIES

Q. What are the purposes of cost of service studies?

A. The primary purpose of a cost of service study is to allocate a utility's overall revenue requirements to the various classes of service in a manner that reflects the relative costs of providing service to each class. In other words, a cost of service study is an analysis of costs that assigns to each class of customers its proportionate share of the utility's total cost of service, i.e., the utility's total revenue requirement. The results of these studies can be utilized to determine the relative cost of service for each customer class and to help determine the individual class revenue responsibility.

The cost of service study provides a reasonable starting point for policy makers to decide the portion of common costs borne by each class of service. In addition, it must be remembered that other constraints impact policy decisions, such as the concept of just and reasonable rates and non-discriminatory rates. The cost analyst must rely on who causes costs and how those costs are recovered within a class of customers as the basis for determining rates that result from the cost of service study.

The cost of service study is useful in identifying cost causation that is a critical element of the allocation of costs between classes and customers within the class, and for adjusting rates to reduce or eliminate cross subsidies that result in rates that are not just and reasonable. A fully unbundled cost of service study provides critical information for the design of just and reasonable rates.

III. PRINCIPLES OF COST CAUSATION

Q. Please discuss the principle of cost causation.

A. Cost studies are a basic tool of ratemaking. Just and reasonable rates must avoid undue discrimination and must reflect the principle of "user pays," also known as "cost causation," which is another way of saying those who cause the costs should pay the costs. The development of unbundled costs permits regulatory review of the costs that are the same on average for customers in the class. The term "on average" is used because no two customers are exactly alike. Therefore, costs are determined, and cost-based rates are set, for "typical" customers grouped by similar demand and usage patterns.

If those costs are not recovered in the customer charge or basic service fee as they should be, the customers with more than average energy consumption subsidize the customers who use less than average. The cost of service study that unbundles customer costs provides a benchmark to assess the rates to determine if they are just and reasonable and do not discriminate based on the rate design.

In order for rates to be efficient the concept of customers being charged for the distinct services they use is important since different customers use different services. Further, the costs of those services may be different because of the different load characteristics of customers in a class. Both cost allocation and rate design play a role in efficient rates.

A properly developed cost of service study represents an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. Understanding cost causation requires an in-depth understanding of the planning, engineering, and operations of the utility system, as well as the basic economics of the unbundled components of the electric system.

Q. Why is the principle of cost causation important?

A. Cost causation is the key element to selecting an allocation method. This has been the standard by which an allocation method is evaluated, and it continues to be the gold standard for assessing cost allocation. The principle of cost causation is also relevant for analysis within classes of customers where each customer must have rates that, on average, match the cost of service for that customer.

Q. What are the measures of demand that may be used in cost allocation?

A. The demands used to develop allocation factors essentially fall into three fundamental categories as follows:

1. Coincident Peak ("CP") Methods
2. Non-Coincident Peak ("NCP") Methods
3. Average and Excess Demand ("AED") Methods.

Q. Please briefly summarize the basic assumptions underlying each potential allocator.

A. The following table summarizes the basic provisions of each category of allocation methods:

<u>Table 1</u>

<u>Cost Allocation Methods Summary</u>

Allocation Method	Assumption about Cost	Allocation Factor
CP	Peak loads drive costs	Class coincident demand
AED	Peak loads and energy usage drive costs	NCP and load factor
NCP	Class or customer peaks drive costs	Class or customer NCP

Q. What methodology was used in the preparation of the UES cost of service study?

A. A combination of a) the class NCP demands, and b) the sum of the customers' NCPs for each class of service were used in developing the UES ACOSS.

IV. DEVELOPING CLASSES OF SERVICE

Q. How are classes of service determined for use in cost of service and rate design?

A. Historically, classes of service have been based on the principle of homogeneity[1]. Typically rate classes have included such categories as:

- Class of service – residential, commercial, industrial
- End-use classification – residential regular, residential all-electric
- Voltage level of service, i.e., secondary, single-phase primary, three-phase primary
- Quality of service – firm or interruptible
- Type of service – full requirements, partial requirements

Having customers with the same usage characteristics allowed relatively simple rate designs to track costs closely with a limited number of rate elements such as a customer charge and a volumetric energy charge.

[1] Definition: Of the same or similar nature or kind; uniform throughout the structure or make-up. Webster's II University Dictionary (1984).

Q. Are there reasons to question the relevance of current customer class structures?

A. Yes. The electric supply market has been changing for years. Perhaps the most important change has been the development of a mix of competitive service offerings for electricity generation coupled with the continued monopoly status of other components of electric utility service. Where there is a mix of competition and monopoly in the market, the definitions of classes of service and the related rate structures must evolve to provide for more efficient electricity markets and for rates to be just and reasonable, and not unduly discriminatory. The first step in this process is developing fully unbundled cost of service studies as the foundation for properly designed rates.

Q. How should classes of service be developed in the future based on the unbundled cost of service?

A. It turns out that some of the same concepts that matter today will also matter even more in the future as class costs are evaluated. The following list provides the major elements that will be used to develop rate classes:

1) Voltage level of service
2) Size of load
3) Unique load characteristics and service attributes
4) End-use load characteristics.

The voltage level of service is necessary to reflect the cost of distribution facilities and the loss adjustments for both energy and capacity related costs at the point of delivery. The size of the load will be a driver of the appropriate customer related costs because of the higher total cost of local facilities. Unique load and service attributes also impact costs. For customers that have one of a kind service requirements there will be a need to ensure cost recovery for the unique facilities required to provide service. Certain end use load characteristics must also be identified and managed such as leading or lagging power factor considerations or extra reliability requirements as examples.

V. THE COST OF SERVICE STUDY PROCESS

Q. What are the basic steps in developing a cost of service study?

A. Cost of service studies use a three-step process as follows:

1. Functionalization
2. Classification
3. Allocation

Q. Please explain the functionalization process.

A. A systematic process for identifying functions is used based on the traditional categories of production, transmission, distribution, and customer. To the extent permitted by the accounting data, this functionalization may include subcategories such as primary distribution and secondary distribution and directly assigned dollars based on unique facilities that need to be assigned rather than allocated. The process of functionalization has become a more robust and simplified process with the use of accounting data as reported under a uniform system of accounts ("USOA"). That is not to say that all of the issues have been resolved. Certain accounts such as intangible plant still require some analysis to functionalize individual cost elements in the account for some utilities. The typical functions used in a cost study are as follows:

- Production/Supply
- Transmission
- Distribution[2]
- Customer

Each of these functions is described below.

The Production function consists of the costs of power generation and purchased power. This includes the cost of generating units and fuel for the units. In addition, any cost of purchased power along with the cost of the delivery of purchased power is also functionalized as production.

The Transmission function consists of the assets and expenses associated with the high voltage system used by the power system to interconnect with the distribution grid and to move power from generation to load.

The Distribution function includes the system that connects transmission to loads. Different customers use different components of the distribution system. In

[2] It is common for distribution costs to be broken out by voltage levels. In UES's case – primary and secondary

recognition of this fact, it is common for the distribution system to be divided into sub-functions such as primary and secondary. In addition, some distribution facilities serve a customer function and are allocated between distribution and customer service accordingly.

The Customer function includes plant and expenses caused by individual customers. Customer service includes meters, service lines, meter reading and billing. It also includes a portion of the distribution system including transformers, conductor, and poles.

Q. Please describe the cost classification step?

A. Cost classification is driven by as detailed an analysis as the accounting data permits. Costs are classified as demand, energy, and customer. Only costs that vary with energy are classified as energy. The costs classified as demand are those costs that are a function of some measure of demand. Customer costs are those costs that vary with the number of customers. For some of the costs associated with the distribution system, costs must be split between the portion that is demand related and the portion that is customer related. That split is based on the principles of cost causation, as discussed above. The classification step is critical to developing allocation factors that reflect cost causation. In particular, it is imperative to understand not only the accounting basis for costs but the engineering and operational analysis of the system as it is planned, built, and operated.

Q. Please elaborate on the nature of the cost classification categories.

A. *Demand* costs are capacity related costs associated with plant that is designed, installed, and operated to meet maximum electric usage requirements such as larger transformers or more localized distribution facilities, which are designed to satisfy individual customer maximum demands. Measures of maximum demand include coincident peak demand, class non-coincident peak demand and customer non-coincident peak demand.

Energy costs are those costs that vary directly with the production of energy such as fuel costs; other fuel related expenses or purchased power expense.

Customer costs are incurred to extend service to and attach a customer to the distribution system, meter any electric usage, and maintain the customer's account. Customer Costs are largely a function of the number and density of customers served and continue to be incurred whether or not the customer uses any electricity. They may include capital costs associated with minimum size distribution systems, services, meters, and customer billing and accounting expenses.

Q. Can costs be classified into more than one category?

A. Yes, as mentioned earlier. For example, some distribution costs may have both a demand and a customer cost component.

Q. Please describe the allocation process?

A. Allocation is based on the factors that cause costs to be incurred. Cost studies use two types of allocation factors: external factors and internal factors. External allocation factors are based on direct knowledge from data in the utility's accounting and other records such as the load research data. Energy allocation factors are based on the class energy consumption and adjusted for losses to equate to total energy production. Another example of an external allocation factor is allocation of distribution system costs, both the demand and customer components. The costs of distribution facilities are known and assigned directly to the distribution function as substations, poles, towers, and fixtures, overhead and underground conductors, transformers, service lines and meters. Once assigned to distribution, the poles and conductors are allocated using the minimum system to classify the costs between demand and customer related costs and then are allocated on external allocation factors. Demand allocation factors are based on load research data that is used to calculate the demand for the sampled rate classes and is adjusted to equal system peaks. For some classes the peak data for the class comes from billing data and represents the sum of actual customer loads occurring at the system peak. As smart meter technology becomes more ubiquitous, the need to estimate the class load will no longer be necessary as meter data will be available. Internal allocation factors are based on some combination of external allocation factors, previously directly assigned costs, and other internal allocation factors. For example, the allocation factors for property insurance costs are based on plant investment amounts assigned to each function; therefore, it is necessary to compute the amount of plant by function before property insurance costs can be assigned.

Q. How do the principles and processes you have explained pertain to fixed costs and variable costs?

A. In the utility ratemaking context, fixed costs include all of those costs that do not vary with the amount of energy consumed by customers and constitute the vast majority of the cost to provide service.

Variable costs include only those costs that vary with the amount of energy consumed by the customers. In other words, variable costs relate directly to how much power is actually consumed; these costs include fuel, the energy component of purchased power costs, reagents used in generation for the operation of emission control systems, and any O&M costs directly related to energy production.

All other costs incurred by the utility are fixed costs because the utility must incur them in order to be capable of providing service whether or not customers actually consume any energy.

Q. How do the functionalized and allocated costs in an ACOSS fit into the fixed and variable cost framework?

A. The only variable costs in UES's cost of service are those designated and allocated as production-energy costs and transmission-energy costs from transmission by others. All of UES's other costs are fixed. That would include the following categories:

- Electric Procurement Supply[3]
- Radial Transmission[4]
- Distribution demand (Primary and Secondary), and
- Distribution customer (Primary and Secondary)
- Customer Service[5]

For UES, the transmission costs are recovered in the External Delivery Charge ("EDC") mechanism and are thus excluded from base rates. While all of these costs are fixed, most are recovered based on energy consumption.

Q. Is it common for utility rates in general to properly reflect fixed and variable costs of providing service?

A. No. In fact, it is rare for the rates of a utility like UES to perfectly reflect the fixed and variable costs of providing service. For many utilities, significant portions of total fixed costs are often recovered in variable charges. This is particularly true for the residential and small commercial or general service rate classes. This treatment of a portion of fixed cost as a variable cost creates pricing inefficiencies that can have adverse consequences to utility customers under certain conditions.

[3] Until Energy assigns Prime Movers to this function.

[4] Unitil Energy has no transmission plant but does book some labor-related O&M expenses.

[5] Unitil Energy has two customer functional categories, Customer Accounts and On-Site.

Q. How does the incorporation of fixed costs into variable charges affect customers?

A. The inclusion of fixed costs in the variable charge sends an inaccurate price signal to customers. This price signal overstates the value of energy consumption and understates the costs necessary to be able to provide service regardless of how much energy the customer uses. This inaccuracy essentially overcompensates the customer for energy conservation/efficiency and under compensates the utility for the assets and facilities that are needed to provide customers with any amount of electric service. Conversely, this inaccuracy also overcompensates the utility for its fixed costs when customers use large amounts of energy. The result of this inaccuracy is essentially an intra-class mismatch of costs and revenue.

When a customer conserves energy, the utility produces less energy, and thus incurs less energy production cost (e.g., fuel or purchased power). This should amount to a dollar-for-dollar savings for both the customer and the utility. However, when a customer conserves energy, the utility does not incur lower fixed costs, like capital investments in substations and poles (distribution demand), or meters, billing, or customer service representatives (customer). When some customers are able to reduce their energy consumption, they avoid paying fixed costs that the utility continues to incur to provide the customer with needed services. Ultimately, those costs will be shifted to other customers.

VI. SELECTION OF CLASS COST OF SERVICE FOR UES

A. Characteristics of Distribution Plant

Q. Please discuss the nature and characteristics of distribution plant

A. The UES system distribution plant consists of different facilities that have different cost causation factors. The reason for this conclusion is threefold. First, load diversity increases as the cost becomes more remote from the individual customer. Second, some facility cost is directly the result of the individual customer and is caused by the customer unrelated to demand. These facilities include the meter and service line. Third, other local facilities have both a customer and a demand component. Transformers are sized to meet the NCP of the customers served from a single transformer but utilities do not install every possible size of transformer. Instead, utilities use a standard set of transformer sizes and one of those is the transformer that represents the minimum size. Transformer costs exhibit significant scale economies. This means that the smallest size of transformer costs much more per kVa than larger transformers. Given the fact that utilities typically use a minimum size of transformer, the cost of the minimum size is related to a customer since every customer requires transformer capacity.[6] For transformers larger than the minimum size, the remainder of transformer cost is related to

[6] For larger customers, the customer may provide its own transformers. These distinctions are typically reflected either as transformer credits in rates (UES's method) or a separate rate schedules for different service classes defined based on use of distribution facilities.

demand. The portion related to demand is based on the customers served from each transformer and represents a much smaller share of costs than the customer component. Given the proximity of the customers to transformers, there is limited diversity for transformers that may serve a few customers and no diversity if a transformer serves only one customer. Thus, transformer demand is related to the individual customer NCP. The NCP for the system based on the sum of individual customers is much higher than either the system coincident peak or the sum of the class NCPs. For facilities located close to the customer such as transformers, secondary conductor, secondary poles, and even single-phase primary conductor, both a customer component and the individual NCP allocation factor is the most appropriate. As the cost becomes more remote from the customer, it is the class NCP that drives the costs. This applies to the demand portion of primary poles and primary conductor. The substation related investment is based on the class NCP allocation factor alone. In fact, any number of substations peak at different times and even different seasons from the coincident peak demand of the utility.

Distribution costs differ based on the portion of the system used by different classes of service. In fact, some customers make no use of the distribution system at all. Where customers own their own substation and connect directly to the transmission system, the customer causes no distribution costs for the utility. These customers are typically served either through special contracts or under a transmission service rate schedule. Further, not all customers use the same level of distribution facilities. For example, customers may own their own transformers. Some larger customers may be served at primary voltages only and thus use no secondary facilities. For very large customers, the customer may use only the three-phase primary system operating at the upper end of voltages for the primary system. Where the utility data supports the identification of the facilities at a detailed level, it is possible to reflect the actual facilities used. Distribution costs may differ based on the facilities required to serve some customers. Some loads require extra facilities to serve a load based on unique load characteristics such as low power factor or frequency regulation for intermittent loads. In that case, the customer may require special rate provisions such as a facilities charge to pay for the extra investment. When customers who have common load characteristics, i.e., "homogeneous" load characteristics, they may warrant a separate class of service. This is particularly important to recognize that partial requirements customers require their own class of service because of the unique load characteristics of this type of customer.

For distribution costs found in Account Nos. 364 – 374 either all or a portion of the costs are customer related because they are caused by customers. There is no basis for arguing that Account Nos. 369 – 373 are not customer related. For Account No. 369 – Services, each customer has a service designed to meet that customers own load characteristics. The service line is dedicated to the customer to meet the load of the customer premise. Services are dedicated to a customer and each customer causes the cost of its service even if the customer never consumes any energy beyond a single light bulb. If the customer is able to avoid all volumetric electric charges and pays only a nominal, non-compensatory customer charge the result is not just and reasonable and is a case of undue discrimination unless that minimum charge covers not only the service line costs but the component of all of the other distribution costs related to providing the customer access to the electric system.

Electricity will not flow into a premise without an electric meter (Account No. 370). For smaller customers, meters are virtually the same for each customer. As customers increase in size, the meter installation becomes increasingly complex and the cost of meter sets increase. In addition, Account Nos. 371 - 373 represent facilities that are also customer related. In the case of these facilities, the customers who request the extra service provided by these facilities typically pay for these directly as in the case of Account No. 373 related to outdoor lighting. In addition to the costs of Account Nos. 369 - 373, a customer cannot be connected to the system without and cannot receive service without a minimum level of distribution services provided through the assets in Account Nos. 364 – 368. These accounts support the basic distribution facilities that must be extended to connect new customers to the system. All existing premises were at one time new customers for whom the system must have been extended. Further, the utility must continually replace aging infrastructure to continue to serve these customers regardless of their annual kWh usage. In the case of these distribution facilities, the minimum size of equipment commonly installed under current policies and procedures represents the costs caused by customers in order to connect the minimum load to the system. The minimum system concept assures that customers who cause the costs of facilities to interconnect to the utility are properly allocated those costs.

B. Allocation of Customer Costs

Q. Please discuss the allocation of customer related costs.

A. There are costs other than distribution plant that are customer related and should be included in the customer cost allocation. First, a portion of the O&M associated with the distribution plant accounts that are allocated on both customer and demand are appropriately allocated to customer costs. In addition, where all of a plant account is allocated as customer related, all of the associated O&M costs should also be allocated to customer costs. Second, customer service-related expenses should be fully allocated to customer costs. Third, a portion of general plant costs should be allocated to customer costs to include such items as customer service facilities and other types of facilities such as the meter shop, stores and tools and equipment. Fourth, a portion of administrative and general ("A&G") expenses should be allocated to customer costs as well. The allocation of general plant and A&G costs is based on the requirement that significant overhead costs are related to direct payroll costs included in the O&M accounts for distribution and customer service expenses. This is the concept of capturing the fully loaded costs of the service provided and includes not only workspace costs but pension and benefits cost and other items related directly to employee costs.

C. Distribution Plant

As noted above, distribution plant is classified as demand, demand and customer, or just customer depending on the costs. Each component of the distribution system requires a different allocation factor based on the classification of the costs and the role that diversity plays in causing the costs. For plant functionalized as distribution plant and found in accounts related to facilities associated with distribution substations (Account Nos. 360 – 363), the plant is classified as demand and is allocated on the class contribution to the system NCP. Substations reflect the diversity of the customers served out of a particular substation. Typically, substations have different mixes of customer class and loads. As a result, substations often peak at times different from the system peak loads. Some substations may even have peak loads in a different season of the year than the system. The use of the sum of the class NCPs accounts for the differences that occur in the capacity demand on substations. Diversity of load on the distribution system is greatest at the substation level where multiple feeders serve a variety of customers and loads.

For distribution facilities in the accounts related to the power lines (Account Nos. 364 – 368) where power is delivered to the interconnection point with the customer, the costs are classified as both customer and demand. While there are several methods to classify these costs between customer and demand, the minimum system approach is the most consistent with cost causation because it represents the actual cost of connecting a customer to the system to serve the minimum load that meets the parameters of the approved line extension policy. Any investment, greater than the minimum system, must be related to the customers' maximum demands on that portion of the system. Thus, in addition to the customer allocation, the demand allocation is based on the sum of the customers' NCPs for each class of service. For the remainder of the distribution accounts (Account Nos. 369 – 373), the costs are classified as customer and are allocated on a customer basis with as much direct assignment of costs as possible. The final distribution account (Account Nos. 374) is related to amortization of PCB related costs and is allocated based on the transformer investment.

D. Other Allocation Factors

Q. Please describe other types of allocation factors within the ACOSS.

A. There are numerous other allocation factors in the ACOSS. Fuel and purchased power expenses are allocated on energy as are certain fuel related O&M costs. O&M costs for the various plant functions are allocated as the associated plant is allocated. There are a number of internal allocation factors that distribute costs according to the factor or factors causing those costs. Thus, an expense like pension expense is allocated on payroll and flows through to the payroll cost component of O&M accounts and ultimately is allocated as the plant is allocated. General plant investments are allocated on labor as well. Intangible plant is analyzed to determine the cause of costs and the components are classified to customer or demand based on the nature of the costs. In each case, the intent of the chosen classification and allocation is to reflect the most appropriate cause of the costs given the level of detail available to analyze the costs.

VII. SUMMARY OF THE ALLOCATED COST OF SERVICE STUDY

Q. Please summarize the results of the recommended cost of service study.

A. The following **Table 2** provides a high-level summary of the results of the ACOSS. The table 2 shows the rate of return for each rate class based on current rates as well as the system overall return and the revenue deficiency or excess for each rate class at the uniform system rate of return.

TABLE 2

RATE OF RETURN AND (REVENUE DEFICIENCY) / EXCESS BY RATE CLASS

(A)	(B)	(C)
RATE CLASS	**RATE OF RETURN BY CLASS**	**REVENUE EXCESS OR (DEFICIENCY) IN THOUSANDS**
D - DOMESTIC DELIVERY SERVICE	-1.01%	($17,935)
G2 - REGULAR GENERAL SERVICE	15.14%	$3,564
G1 - LARGE GENERAL SERVICE	16.00%	$1,937
OL - OUTDOOR LIGHTING	21.94%	$443
TOTAL SYSTEM	4.01%	($11,992)

Q. Do these results provide guidance for the allocation of revenue requirements in this case?

A. Yes. Cost of service is a useful tool for determining the allocation of the revenue deficiency to each rate class. Cost of service is not, however, the only consideration in determining the portion of the revenue deficiency allocated to each rate class. Other considerations include principles such as gradualism, competitive considerations, standalone costs and avoiding or minimizing the potential for compromising the integrity of current rate classes.

Q. Has UES taken the above factors into account in recommending the level of rate increase for rate classes?

A. Yes. The process for determining the revenue increase for each class is addressed in **<u>Section VIII</u>** of this testimony.

Q. Please describe the ACOSS schedules attached to this testimony.

A. Six schedules provide further details of the ACOSS that include the following information:

- Schedule RJA – 2, consists of two pages and presents the results of the class cost of service study for the test year. Class rate of return and net income may be found on page 1, and the revenue requirement for each class at the uniform rate of return by rate schedule is shown on page 2 of this schedule.
- Schedule RJA – 3, provides a single page illustration of the process followed to develop the Company's proposed class revenue allocation.
- Schedule RJA – 4, consists of 3 pages and presents the ACOSS unit cost report.
- Schedule RJA – 5, consists of 3 pages and provides the summary of the ACOSS external allocation factors.
- Schedule RJA – 6, consists of 5 pages and provides a description of the functionalization and classification of the USOA accounts.
- Schedule RJA – 7, presents a single page summary of the Minimum System Study.

VIII. DETERMINATION OF PROPOSED CLASS REVENUES

Q. Please describe the approach generally followed to allocate UES's proposed revenue increase of $11,992,393 to its customer classes.

A. The apportionment of revenues among customer classes consists of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. The various criteria that were considered in the process included: (1) cost of service; (2) class contribution to present revenue levels; and (3) customer impact considerations. These criteria were evaluated for UES's customer classes.

Q. Did you consider various class revenue options in conjunction with your evaluation and determination of UES's interclass revenue proposal?

A. Yes. Using UES's proposed revenue increase, and the results of its ACOSS, I evaluated a few options for the assignment of that increase among its customer classes and, in conjunction with UES personnel and management, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. The benchmark option that I evaluated under UES's proposed total revenue level was to adjust the revenue level for each customer class so that the revenue-to-cost for each class was equal to 1.00 ("Unity"), as shown in Schedule RJA-3, Proposed Revenue Allocation, under *Revenues at Equalized Rates of Return*. As a matter of judgment, it was decided that this fully cost-based option was not the preferred solution to the interclass revenue issue. It should be pointed out, however, that those class revenue results represented an important guide for purposes of evaluating subsequent rate design options from a cost of service perspective.

A second option I considered was assigning the increase in revenues to UES's customer classes based on an equal percentage basis of its current non-gas revenues (*Scenario A, Equal Percentage Increase,* in Schedule RJA-3). By definition, this option resulted in each customer class receiving an increase in revenues. However, when this option was evaluated against the ACOSS results (as measured by changes in the revenue-to-cost ratio for each customer class); there was no movement towards cost for most of UES's customer classes (*i.e.*, there was no convergence of the resulting revenue-to-cost ratios towards unity or 1.00). In fact, the disparity in cost responsibility between the classes was widened. While this option was not the preferred solution to the interclass revenue issue, together with the fully cost-based option, it defined a range of results that provides further guidance to develop UES's class revenue proposal.

A third option was to exempt the customer classes that are above parity under current rates from receiving any revenue increase. This option would preserve the current parity ratio for the G2 – Regular General Service and G1 – Large General Service classes (*Scenario B, No Class Increase Above Parity*, in Schedule RJA-3).

Q. What was the result of this process?

A. After further discussions with UES, I concluded that the appropriate interclass revenue proposal would consist of adjustments, in varying proportions, to the present revenue levels in all but one of UES's customer classes: D – Domestic Delivery Service, G2 – Regular General Service, and G1 – Large General Service, as shown in Schedule RJA-3 as *Scenario C, Minimum Class Increase of 50% of System Average*. In the case of the D – Domestic Delivery Service class, the revenue adjustment ensures their proposed rates will move class revenues closer to the allocated cost of service for the class. The proposed revenue increase to the D – Domestic Delivery Service class will improve the class' revenue-to-cost ratio from 0.64 to 0.83, below unity (1.00) at the Company's proposed ROR of 7.88%. The ACOSS results for the remaining customer classes indicate their respective class rates of return are above the system average rate of return at both the Company's current and proposed ROR levels. While this would suggest the need for revenue decreases in order to move many of these customer classes closer to cost (*i.e.*, convergence of the resulting revenue-to-cost ratios towards unity or 1.00), as shown in Schedule RJA-3 under *Revenues at Equalized Rates of Return*, the resulting customer impact implications for the Residential Service class has led me to conclude the Company should refrain from revenue reductions for the G2 – Regular General Service, and G1 – Large General Service customer classes, or alternatively, exempting these classes from revenue increases (*Scenario B*). Instead, the proposed respective revenue adjustments of 50% of the system average increase will mean these two classes will be higher than their current parity ratio levels relative to unity. However, the interclass subsidy gap between these classes and the D – Domestic Delivery Service will be narrowed. I have refrained from proposing a revenue increase for the Outdoor Lighting customer class.

Q. What was the reason for exempting the Outdoor Lighting class from a revenue increase?

A. UES is anticipating a transition from the legacy outdoor lighting fixture technology (Mercury Vapor, Sodium Vapor, and Metal Halide) currently deployed in its distribution system, to new LED technology over the course of the next few years, which should reduce outdoor lighting service costs, in addition to lower energy costs. Replacement of the legacy light fixtures with LED light fixtures will reduce O&M costs associated with a longer maintenance cycle, currently five years for replacement of photo receptors and light bulbs. The expected maintenance cycle for replacement of photo receptors in the LED light fixtures will range from 10 to 13 years. The LED fixtures also have an extended useful life over the various legacy light fixtures. Therefore, the Company does not wish to increase revenue to the Outdoor Lighting class at this time and further exacerbate the current revenue surplus provided by this class when the proposed rate of return with no revenue increase will be over 2.5 times the system average return at 20.54%, the largest of any class.

Q. Please summarize the overall benefit provided by your proposed class revenue apportionment.

In summary, the preferred revenue allocation approach in Schedule RJA-3, *Scenario C* results in reasonable movement of the Residential class revenue-to-cost ratio toward unity or 1.00, while providing moderation of the revenue impact on this class by requiring some level of revenue increase responsibility from the G2 – Regular General Service, and G1 – Large General Service customer classes for the Company's total proposed revenue requirement. From a class cost of service standpoint, this type of class movement, and modest reduction in the existing class rate subsidies, is desirable.

IX. UNBUNDLED COST OF SERVICE

Q. Does the cost of service study provide useful guidance in developing rate structures and rate levels?

A. Yes. When a cost of service study is fully unbundled another output from the study is the cost for each service actually provided. From the cost of service study, we have prepared Schedule RJA–4, which summarizes the functionalized and classified rate base and revenue requirements for each rate class on pages 1 and 2 of the schedule; and presents a summary of unit costs for each rate class by function and cost classification on page 3. These values form the basis for beginning the process of designing rates.

Q. How were these unit costs calculated?

A. For each functional category of costs permitted by the detailed cost of the utility, the cost study calculates the costs classified as demand, energy or customer and sums those costs. The limit on unbundling details is based on the type of account information provided. For example, if detailed data exists to unbundle distribution assets into primary and secondary facilities, the demand component of each voltage level of distribution service may be unbundled. Each rate is based on the unit costs resulting from the allocation of class costs in each classification.

Q. Please explain how the unit costs can be used for rate design.

A. The unit costs provide useful information for the design of portions of tariff services, in particular for establishing cost-based customer charges. The unit costs also can be used to design demand charges where either interval metering is available or algorithm-based billing demands can be determined. Demand based rates provide for a charge based upon the maximum demand imposed by a customer on the utility's system within a specified time period, which establishes both the utility's responsibility to serve and the customer's obligation to pay for that level of service.

Q. Why is it important to determine unbundled costs?

A. The electric industry has been evolving into the mixed monopoly and competition model as a result of competitive supply options, including distributed generation ("DG"). DG can take many forms, including renewables such as wind or solar, combined heat and power, fuel cells and other forms of generation. Each of these forms of DG makes different use of utility service in general and even different uses within the same technology all based on the economics of the competitive options.

Historically, most all utility customers could be identified as full requirements customers; that is, the customers purchased all of their electric capacity and energy needs from the utility. A single rate applied to a homogeneous group of customers was adequate to recover the costs of this service. Today, more customers want to choose to be partial requirements customers. These customers want to explore competitive supply and self-generation options for a portion or all of their energy requirements. In this mixed monopoly and competition model, in order to avoid subsidization by non-DG customers to DG customers, it is important that customers who elect to self-supply a portion of their energy needs continue to pay the costs not avoided by the utility. Efficient decisions require that customers understand and pay for the costs of the portions of the system they use and any additional costs they cause the system to incur to support their technology being interconnected to the system.

In an environment of increasing DG penetration, current rate structures do not provide economically efficient price signals to customers. Instead, current structures create artificial and unsustainable cross-subsidies that result in misallocation of resources. In addition, rates as they are currently designed permit undue discrimination for customers using the very same services but paying different effective charges for those services.

Q. What services will a utility provide in the mixed monopoly and competition concept?

A. As long as the customer is connected to the utility system the utility must provide that connection capacity, and that connection capacity must be large enough to deliver service to the customer based on the maximum demand of the customer. Additionally, the utility will need to meter and bill for service that is provided and to account for energy delivered by the DG customer to the utility. Thus, customer-related costs will also continue and may even increase when customers install DG.

Since the maximum demand of a partial requirements customer may be no different than a full requirements customer, the partial requirements customer will pay far less to have the utility available to provide service than a full requirements customer when the fixed costs associated with standing ready to provide service are in per kWh charges. The simple reason is that a class that includes both full requirements customers and partial requirements customers is no longer homogeneous. Even separating the classes cannot solve the fundamental issue that different customers require different services and even different levels of those services. Rates need to be designed to provide an economically efficient and just and reasonable solution to the issue even if the class of service does not change.

Q. How does the recovery of capacity costs through demand charges benefit customers?

A. There are a number of benefits for customers as they plan their use of electric service. First, customers will know the cost of each service they use. When the cost is known, customers will be able to make better, cost-effective decisions about how they use both the utility services and the competitive services. It is important that customers really understand how an investment will change their utility costs before they spend their money on new technology.

Second, when customers pay the actual costs they impose on the utility, both the utility and the customers make better long-term decisions about resource requirements. These decisions have a much broader impact than individual customers and go to the development of the optimal plan for the utility to meet its obligations in the future given the existing sunk cost of assets currently providing utility services. This decision-making ultimately benefits customers in terms of a safe, reliable, and economically efficient utility system.

Finally, when customers know the cost of their decisions, they will properly evaluate the decision and minimize the cost of utility service.

X. MARGINAL COST OF SERVICE STUDY

Q Please describe the purpose for the preparation of a marginal cost of service study?

A. Marginal cost of service studies do not typically reflect actual costs but rely on estimates of the expected changes in costs associated with changes in service levels; and are therefore, forward-looking to the extent permitted by the available cost data. Marginal cost studies are most useful for rate design where it is important to send appropriate price signals associated with additional consumption by customers. Marginal cost studies can inform rate design particularly as it relates to customer and demand related costs for a utility that provides default energy services to retail customers who do not elect an alternate energy supplier. Marginal costs are also important for determining optimal seasons and time-of-use (TOU) periods when designing TOU rates.

Q. Please describe the Company's MCOSS.

Marginal cost studies focus on the change in costs associated with a small change in the number of customers or load added to the utility's system, or the cost to replace the current customer related infrastructure to continue service to an existing customer. As stated earlier, marginal costs are generally forward-looking and require making estimates of future costs with an understanding of the elements that drive those future costs. As a practical matter, marginal costs bear no relationship to the mix of actual historical costs that constitute the utility revenue requirement. The reasons that marginal costs do not reflect actual costs used in a utility's revenue requirement calculations include the following:

- The relationship between historic and prospective costs reflects changes in technology.
- Sunk costs (the fixed cost of the existing system) do not impact marginal cost but may account for a large portion of the test year revenue requirement particularly where economies of scale are significant.
- The underlying impacts of inflation on prospective costs cause such costs to differ from past costs.
- Additions to the utility system are lumpy, and as a result, utilities' optimal additions often include more capacity than the marginal change in customer count or customer demand.

To estimate marginal cost, the first step requires determining the change in cost associated with the addition of a new customer or load on average. Electric distribution systems (from the customer's meter up to the feeder coming from the distribution substation) are typically built using engineering design standards that take into consideration customer density and the expected design loads of those customers. Distribution facilities for larger commercial and industrial customers are generally designed on a case-by-case basis, given the expected peak load of the customer. In short, the local distribution system is designed based on the design load of the customers to be served ultimately, not specifically on the number of customers or their actual loads at any given moment.

The concept of a network cost provides a convenient way to discuss the marginal distribution costs. Network costs represent the cost of the interconnected facilities that serve local loads and include substations, feeders, transformers, service drops and meters. Feeders may be primary or secondary lines depending on the location of the customer and the design of the system. The customer component of these systems is related to the smallest size of the equipment that is installed to serve customers. If larger equipment is installed, the extra costs are demand related. The economies of scale in the distribution system mean that the demand related cost is much less significant than the customer component. It also means that per unit cost of serving larger customers is lower than the cost to serve smaller customers.

Q. How have you identified the minimum size components used by UES in its delivery system?

A. Yes. The distribution engineering and operations personnel at UES were interviewed to gain an understanding of the smallest standard size of facilities used. In addition, the Company's accounting function personnel were consulted to determine the fully loaded installed costs of these components. Schedule RJA-7 provides the cost of the minimum system components. The cost of substation equipment was considered fully demand related. For the primary system, transformers, and secondary system, the minimum system study was used to classify costs as customer-related or demand-related. Meters and services are considered entirely customer related. The MCOSS schedule also provides the economic carrying charge rate for each plant component. The schedule produces the marginal revenue requirement for UES associated with customer and demand related capital expenditures. The economic carrying charge rate uses UES's marginal capital costs based on the current filing. The forward-looking nature of a marginal cost study requires that the capital cost be estimated on an incremental basis not on embedded costs.

Q. Did you identify the general plant related to the minimum system?

A. Yes, the customer and demand related general plant was identified based on average embedded costs as a proxy for long-run marginal costs.

Q. Why are average embedded costs a reasonable proxy for marginal costs?

A. General plant costs do not vary directly with either demand or customers. That is the reason that in the allocated cost of service they are allocated on composite allocation factors. For example, customer growth only impacts the number of employees and therefore payroll expense when large discreet blocks of customers are added. If we used a pure marginal cost allocation factor, the payroll component growth related to customers or demand would be zero for a number of years and would be the full cost of a new employee only when the threshold number of customers requiring additional employees reached the tipping point in the level of services provided. By using an average cost value, the marginal cost study recognizes the contribution of each new customer to the future requirement of a new employee or new office space.

Q. Have you identified the customer related expenses?

A. Yes. The customer related expenses may be found in Schedule RJA-8, which presents the Company's full marginal cost study. These expenses were based on embedded costs as a proxy for long-run marginal costs. In the short run, these costs would be zero because adding one customer does not change most of these costs. However, at some level these costs would increase by an amount related to the average cost when a minimum number of customers have been added. This approach provides a reasonable proxy for the O&M related costs.

Q. Did you identify the A&G costs related to the minimum system?

A. Yes, customer and demand related A&G costs were identified based on embedded costs as a proxy for long-run marginal costs.

Q. Please summarize the results of the company's customer and demand costs on an embedded and a marginal cost basis.

A. The results are summarized in the table below.

TABLE 3

	Unit Customer Costs ($/Month)		Unit Demand Cost ($/KW-Month)	
(A)	(B)	(C)	(D)	(E)
Rate Class	Embedded	Marginal	Embedded	Marginal
D - DOMESTIC DELIVERY SERVICE	42.07	46.24	8.46	6.61
G2 - REGULAR GENERAL SERVICE	50.13	59.48	7.81	5.25
G1 - LARGE GENERAL SERVICE	148.40	151.47	7.22	4.15
OL - OUTDOOR LIGHTING	11.24	6.73	7.48	4.56
TOTAL SYSTEM	40.13	44.07	8.03	5.74

As the table illustrates, the D – Domestic Service customer-related costs calculated in both cost studies are significantly greater than the current customer charge. Thus, a customer facilities-related charge increase is warranted and consistent with the indicated cost of service. Increasing the customer charge and reducing the kWh charge is also consistent with both marginal cost pricing and achieving just and reasonable rates.

Q. Would the proposed allocation of the company's proposed revenue requirements differ based on using marginal costs instead of embedded costs?

A. Any differences would not be material. Considering the Company's proposed revenue allocation, the end result would have been the same. However, there is more long-term stability in embedded costs, and it is more reflective of the cost causation principle. Therefore, I believe the ACOSS is a more reasonable alternative.

Q. Does this conclude your testimony?

A. Yes.

[THIS PAGE INTENTIONALLY LEFT BLANK]

Ronald J. Amen

Managing Partner

Mr. Amen has over 40 years of combined experience in utility management and consulting in the areas of regulatory support, resource planning, organizational development, distribution operations and customer service, marketing, and systems administration.

He has advised gas, electric and water utility clients in the following areas: regulatory policy, strategy, and analysis; cost of service studies (embedded and marginal cost analyses); rate design and pricing issues including time- of-use rates, revenue decoupling, weather normalization and other cost tracking mechanisms; resource strategy, planning and financial analysis; and business process design, evaluation, and organizational structures. Mr. Amen has provided expert testimony in numerous state and provincial regulatory agencies, and the Federal Energy Regulatory Commission. Prior to establishing Atrium Economics in 2020, Mr. Amen's consulting experience included Director Advisory & Planning at Black & Veatch Management Consulting, LLC, Vice President of Concentric Energy Advisors, Inc. and Director with Navigant Consulting, Inc. His prior utility experience includes leadership of State and Federal Regulatory Affairs at two electric and gas utilities, and management positions in Regulatory Affairs, Information Systems and Distribution Operations.

EDUCATION

Bachelor of Science with Distinction, Business Administration, Finance and Economics, University of Nebraska, United States

YEARS EXPERIENCE

42

PROFESSIONAL ASSOCIATIONS

American Gas Association

Southern Gas Association

RELEVANT EXPERTISE

Financial Analysis; Litigation Support; Regulatory Support; Strategy; Utility Operations

REPRESENTATIVE PROJECT EXPERIENCE

REGULATORY POLICY, STRATEGY AND ANALYSIS

Western Export Group (2019)

In a Nova Gas Transmission, LTD. (NGTL) Rate Design and Service Application before the Canadian National Energy Board, Mr. Amen led a consulting team supporting the interests of the Western Export Group, a group of nine utility companies located in the Western U.S. and British Columbia who are export shippers on the NGTL system.

Regulatory Commission of Alaska (2019 – 2020)

Part of a multi-functional team that assisted the Regulatory Commission of Alaska (RCA) in its evaluation of the Chugach Electric Association, Inc's acquisition of the Municipal of Anchorage d/b/a Municipal Light & Power Department. Assisted the RCA with its evaluation of the long-term benefits of the transaction to ML&P and Chugach customers, the implication of terms and assumptions in various agreements, and the careful balance of the fiscal and regulatory implications for the customers of the combined entity.

CPS Energy (2017 – 2018)

Provided an overall review of the client's Strategic Roadmap to prioritize its multi-year regulatory initiatives. (e.g., changes in product and service offerings, restructuring of current rate classes, introduction of new rate structures, rate levels, and tariff provisions). Current pricing processes and platforms assessed to identify recommended enhancements to enable the development and implementation of dynamic pricing concepts. Assisted client with preparation of next rate case (e.g., costing and pricing analyses, load forecasting, internal communications, and stakeholder engagement).

FortisBC Energy, Inc. (2016 – 2018)

Performed an overall review of the client's Transportation Service Model. Analyzed the client's various midstream transportation and storage capacity resources used in providing balancing of transportation customers' loads. Review included the physical diversity, functionality and flexibility provided by the various capacity resources, and the cost impact caused by transportation customers' imbalance levels. Conducted an industry-wide benchmarking study of current industry-wide best practices, by regulatory jurisdiction, related to transportation balancing tariff provisions. Participated in stakeholder workshops and testified before the BCUC.

McDowell Rackner & Gibson Law Firm (2015 – 2016)

Provided due diligence services to the law firm in connection with a state utility commission investigation into the law firm client's gas storage and optimization activities. Provided an independent opinion as to the likely outcome of the Commission's ongoing investigation.

Gulfport Energy Corporation (2016)

Provided regulatory analysis and support to Gulfport Energy Corporation in the ANR Pipeline Company Natural Gas Act §4 rate proceeding before the Federal Energy Regulatory Commission (FERC). Analyzed as-filed cost of service and rate design to identify key cost of service, cost allocation, rate design and service related/tariff issues. Developed an integrated cost of service and rate design model to prepare studies on client issues. Prepared best/worst case litigation outcomes, discovery, and evaluations of discovery of other parties. Analyzed FERC staff top sheets and settlement offers; and assisted in the preparation of settlement positions.

Confidential Financial / Energy Partners (2015)

Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas/electric company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Confidential International Energy Company (2014)

Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Pacific Gas & Electric Company (2014)

Developed an extensive industrywide benchmarking study to determine the cost allocation and ratemaking treatment utilized by Local Distribution Companies (LDCs) in the United States for recovery of gas transmission costs. Benchmarked cost allocation and rate design utilized by Interstate/Intrastate Pipelines. Benchmarked how Industrial & Electric Generation customers are served with natural gas.

Public Service Company of New Mexico (2009-2010)

Provided case management, revenue requirement, cost of service and rate design support for general rate cases in the utility's two state regulatory jurisdictions. Issue management and policy development included an electric fuel and purchased power cost mechanism, recovery of environmental remediation costs for a coal fired power plant, and the valuation of renewable energy credits related to a wind power facility.

Confidential International Energy Company (2009)

Provided due diligence on behalf of client related to the purchase of a gas/electric utility, including a review of the regulatory and market-related assumptions underlying the client's valuation model, resulting in the validation of the model and identification of key business risks and opportunities.

RESOURCE PLANNING, STRATEGY AND FINANCIAL ANALYSIS

Fortis BC Energy, Inc. (2011)

Retained to help develop a gas supply incentive mechanism in cooperation with the British Columbia Utilities Commission staff and the company's other stakeholders. Provided an independent analysis of the utility's management of pipeline and storage capacity and supply. Part of this work entailed a review of the major markets in which the utility transacted, reviewing the size of trading activity at the major market hubs, and reviewing the price indices for these markets.

Black Hills Colorado Electric Utility (2009)

Engaged as a member of a consultant team that served as the independent evaluator in a competitive solicitation for non-intermittent generation resources. Jointly recommended by the utility client, the staff of the utility commission and the state attorney general, the consulting team acted as an agent of the public utility commission monitoring and overseeing the solicitation, which included reviewing the request for proposals and solicitation process, including provisions of the power purchase agreement, preliminary review (economic and contractual) of bids received from the request for proposals, initial modeling of bids for screening, selection of bidders with whom to conduct negotiations and oversight of the negotiation process, and the ultimate selection of the winning bid. Provided due diligence review of all input data, preliminary and final model output, and output summaries. The team produced biweekly confidential reports to the commission regarding the process and its results.

NW Natural (2007-2008)

Assisted with the development of its long-term Integrated Resource Plan (IRP) for its Oregon and Washington service territories. The IRP included the evaluation of incremental inter- and intra-state pipeline capacity, underground storage, and two proposed LNG plants under development in the region.

Puget Sound Energy (2007)

Engaged to assist the client with the development of a natural gas resource efficiency and direct end-use strategy, an interdepartmental initiative focused on preparing a natural gas resource efficiency plan that optimizes customers' end-use energy consumption while furthering corporate customer, financial, environmental, and social responsibilities.

Puget Sound Energy (2002 – 2 003)

Provided resource planning strategy and analysis for the company's Least Cost Plan, including a review of the company's underlying 20-year electric and gas demand forecasts. As a member of a consulting team, served as the client's financial advisor for the acquisition of new electric power supply resources. Conducted a multitrack solicitation process for evaluation of generation assets and purchase power agreements. Provided regulatory support for the acquisition.

COST ALLOCATION, PRICING ISSUES AND RATE DESIGN

Montana-Dakota Utilities (2020 – 2021) (Pending)

Provided cost of service, class revenue apportionment, rate design, and expert witness support for the gas utility's general rate cases before the Montana Public Service Commission and the North Dakota Public Service Commission, filed in 2020. Testimony included theoretical principals and practical application of cost allocation, and rate design principles or objectives that have broad acceptance in utility regulatory and policy literature. Supported the continuation of a Straight Fixed-Variable rate design for the residential customer class in North Dakota.

Kansas City, KS Board of Public Utilities (2019 – 2020)

Provided expert witness testimony supporting the basis for a Green Energy Program, its objectives, and overall benefits. Provide an assessment of how the program is aligned with best practices in design of Green Energy tariff programs nationally. Testimony also provided an assessment of how the program mitigates potential risks the to the Board of Public Utilities and protects against subsidization of other rate classes.

NW Natural (2018 – 2019)

Provided cost of service, class revenue apportionment, rate design, and expert witness support for the gas utility's general rate case before the Washington Utility and Transportation Commission (WUTC), filed in December 2018. Testimony included theoretical principals and practical application of cost allocation, and rate design principles or objectives that have broad acceptance in utility regulatory and policy literature.

Chesapeake Utilities Corporation (2018 – 2019)

Developed a Weather Normalization Adjustment (WNA) mechanism applicable to the monthly billings of Chesapeake's residential and general service customers. Sponsored the WNA mechanism through expert testimony filed with the Delaware Public Service Commission in January 2019. The testimony included a description of the WNA calculations; back-casting performance analyses, with bill impacts; a WNA tariff; and conceptual and evidentiary support for this ratemaking mechanism.

Louisville Gas & Electric Company and Kentucky Utilities Company (2018)

Engaged by LG&E and KU to a conduct a study in support of a joint utility and stakeholder collaborative concerning economical deployment of electric bus infrastructure by the transit authorities in the Louisville and Lexington KY areas, as well as possible cost-based rate structures related to charging stations and other infrastructure needed for electric buses.

Summit Utilities – Colorado Natural Gas, Inc. (2018)

Engaged by Summit Utilities to develop and support with expert testimony an appropriate normal weather period for the client's five Colorado temperature zones, resulting normalized billing determinants, and a Weather Normalization Adjustment ("WNA") proposal in conjunction with the filing of a general rate case for its Colorado Natural Gas, Inc. subsidiary.

Westar Energy (2018)

Provided cost of service and expert witness support for the electric utility's general rate case filing before the Kansas Corporation Commission (KCC). The cost of service study determined the cost components for a new Residential Distributed Generation (DG) customer class that provided the basis for recommendations for establishing components of a sound, modern three-part rate design for this new Residential DG (roof-top solar) service, which was approved by the KCC.

Florida Public Utilities (Chesapeake Utilities) (2017 – 2018)

Provided a rate stratification study of the utility's commercial and industrial customer classes to facilitate the reconfiguration of the classes by size of service facilities, annual volume, and load factor. Reviewed the cost allocation bases and recommended alternatives for recovery of capital investments related to the utility's Gas Reliability Investment Program (GRIP).

Tacoma Power (2016 – 2018)

Provided cost of service and rate design support for the electric utility's general rate case filings, including support for recovery of fixed costs through fixed charges and impacts on low-income customers. Provided recommendations as to specifications in the client's cost of service analysis (COSA) model for deriving Open Access Transmission Tariff rates, using FERC approved standards to guide the evaluation. Conducted an electric utility costing and pricing workshop for the PUB in October 2017; and participated with Tacoma Utilities staff in a comprehensive electric and water Rates and Financial Planning workshop in February 2018. Engagement was extended for the 2019 – 2020 rate filing, which will incorporate the Black & Veatch municipal COSA model for costing and ratemaking purposes. Currently working with Tacoma Power for the potential incorporation of financial forecasting capabilities and revenue requirements development into the COSA model. Future project work involves working on the re-design of the general service and industrial rate schedules, economic development rate strategies, demand response rates, and other innovative rate programs.

Tacoma Power (2017)

Engaged to review and assess current rates for 3rd Party Pole Attachments (PA), and more specifically, to determine and recommend if any rate adjustments were needed. Performed several tasks:

- Performed a market survey of rates charged by comparable utilities
- Reviewed current regulations on rate setting and practice for 3rd Party Pole Attachments as set forth by the Federal Communications Commission (FCC) and the State of Washington (WA), and the interpretation of such regulations in court decisions
- Reviewed industry best practices under the FCC, WA, and the American Public Power Association (APPA)
- Collected and reviewed data for cost-based fees including:
- Application Fees
- Non-Compliance Fees
- Reviewed cost data supplied by the City of Tacoma as relates to determining pole costs; and
- Performed modeling of rates under the FCC Model, the APPA model and the State of Washington shared model (50 % FCC Rate/ 50% APPA Rate).

BC Hydro (2016)

Provided research and analysis of the line extension policies of a select group of peer utilities in Canada with similar regulatory regimes as well as U.S. utilities based on their geographic relationship to the client. Conducted interviews with peer utilities to gather comparative information regarding their line extension policies and related internal procedures. Performed a comparative analysis of the various line extension policies from the selected peer group.

Cascade Natural Gas Corporation (2015 – 2019)

Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions, 3 in Oregon and 2 in Washington. Conducted Long-run Incremental Cost Studies in the Oregon jurisdiction and embedded class allocated cost of service studies in the Washington jurisdiction. Performed benchmark analyses to compare each of the client's administrative and general (A&G) and operations and management (O&M) expenses, on a per-customer basis, to various peer groups. Analyses were performed for natural gas utilities and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Represented the client's interests in a Washington generic rulemaking proceeding on the subject of electric and gas cost of service methodologies and minimum filing requirements.

Chesapeake Utilities (2015 – 2016)

For its Delaware jurisdiction, provided cost of service and rate design support in the client's general rate case proceeding, including expert witness testimony in support of the utility's proposed gas revenue decoupling mechanism.

Homer Electric Association / Alaska Electric and Energy Cooperatives (2015)

Represented clients in an ENSTAR gas general rate proceeding. Testimony discusses accepted industry principles of revenue allocation and rate design, including the applicability to and alignment with ENSTAR's revenue allocation and rate design proposals for large power and industrial customers. Provided a critique of certain methodological aspects of ENSTAR's Cost of Service study, proposed revenue allocation, and rate design relating to the various large power and industrial customers.

Arkansas Oklahoma Gas Corporation (2002, 2003, 2004, 2007, 2012, 2013)

Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions and in support of Section 311 transportation filings (2007, 2010) before the Federal Energy Regulatory Commission. Provided related research, design, and expert witness testimony in support of a Revenue Decoupling mechanism in one jurisdiction and a Weather Normalization Adjustment mechanism in the other jurisdiction, along with a significant increase in fixed charges and the introduction of demand charges for the company's largest customer classes. Conducted a pre-filing "decoupling" workshop for the utility commission staff.

Northern Indiana Public Service Company (NiSource) (2009 – 2010, 2013, 2017)

Conducted class allocated cost of service studies for the client's natural gas (including two other affiliate gas utilities) and electric operations. Work included reconfiguring the Company's commercial and industrial customer classes according to size of load and customer-related facilities. Rate design was modernized to recover a greater portion of fixed costs via fixed monthly customer and demand-based charges, a transition to a "Straight-Fixed Variable" form of rate design. Industry research was provided on alternative rate designs for the electric service, including Time-of-Use rates and Critical Peak Pricing. Served as an expert witness on behalf of the client in four general rate cases before the Indiana Utility Regulatory Commission.

Southwestern Public Service Company (Xcel) (2012)

Retained to conduct a study to estimate the conservation effect of replacing its existing electric residential rate design with an alternative rate design such as an inverted block rate design. Reviewed inclining block rate structures that have actively been employed in other jurisdictions and also reviewed technical and academic literature to assess the elasticity of electricity demand for residential customers in the southwestern U.S. Analyzed 2009-2011 residential data to determine what sort of conservation effect the company may expect by implementing an inclining block rate structure. Provided an overview of alternative rate structures which may also promote conservation effects, such as seasonal rates, three-part rates, and time-of-use (TOU) rates and considered the competing incentives of promoting conservation and cost recovery, without specific rate mechanisms to address this conflict.

Atlantic Wallboard LP and Flakeboard Company Limited (JD Irving) (2012)

Represented clients in an Enbridge Gas New Brunswick Limited Partnership ("EGNB") general rate proceeding. Testimony responded to the 2012 allocated cost of service study and rate design that was submitted to the New Brunswick Energy and Utilities Board by EGNB. Testimony also provided benchmark information regarding EGNB's distribution pipeline infrastructure in New Brunswick. CA.

Western Massachusetts Electric Company (Northeast Utilities) (2010 – 2011)

Supported utility in its decoupling proposal for the company's general rate case. Work included: 1) research on the financial implications of decoupling; 2) identification of decoupling mechanism details to address company and regulatory requirements and objectives; 3) identification of rate adjustment mechanisms that would work together with the company's proposed decoupling mechanism; and 4) preparing pre-filed testimony and testifying at hearings in support of the company's decoupling and rate adjustment proposals. The proposed rate adjustment mechanisms included an inflation adjustment mechanism based on a statistical analysis, and a capital spending mechanism to recover the costs associated with capital plant investment targeted to improving service reliability.

Interstate Power & Light (Alliant Energy) (2010 – 2011)

Conducted class allocated cost of service studies for a Midwestern electric utility's Minnesota electric system. Work included reconfiguring the company's customer classes for cost of service purposes to collapse end-use based classes with the classes to which they would be eligible. Cost of service studies were performed on a before-and-after basis for the existing and proposed classes. The cost of service studies included a fixed/variable study for production costs, and a primary/secondary study for poles, transformers, and conductors. Performed a TOU analysis to determine the appropriate rate differentials for its peak and off-peak rates. Served as an expert witness on behalf of the client in a general rate case before the Minnesota Public Service Commission.

National Grid (2010)

Conducted class allocated cost of service studies for the client's Massachusetts natural gas operations. This task included combined gas cost of service studies for the consolidation of four gas service territories into two gas utility subsidiaries. During interrogatories, performed four separate allocated cost of service studies for each gas service territory. Work included reconfiguring the company's commercial and industrial customer classes according to size of load and customer-related facilities. Served as an expert witness on behalf of the client in consolidated general rate cases before the Massachusetts Department of Public Utilities.

Puget Sound Energy (2001 – 2002, 2006 – 2007, 2019 – 2020)

In three Washington general rate proceedings, provided cost of service and rate design support, including expert witness testimony in support of the utility's proposed revenue decoupling mechanism. Conducted research on accelerated cost recovery mechanisms for infrastructure replacement, and electric power cost adjustment mechanisms. In a pending general rate case, Mr. Amen is sponsoring expert testimony on a proposed revenue attrition adjustment to the client's revenue requirement.

UTILITY SYSTEM OPERATIONS AND ORGANIZATIONAL DEVELOPMENT

Philadelphia Gas Works (2017, 2020)

Engaged to provide an independent consulting engineer's report to be included as an appendix to the official statement prepared in connection with the issuance of the City of Philadelphia, Pennsylvania Gas Works Revenue Bonds. The evaluation of the PGW system included a discussion of organization, management, and staffing; system service area; supply facilities; distribution facilities; and the utility's Capital Improvement Plan (CIP). Our report also contained: (a) financial feasibility information, including analyses of gas rates and rate methodology; (b) projection of future operation and maintenance expenses; (c) CIP financing plans; (d) projection of revenue requirements as a determinant of future revenues; (e) an assessment of PGW's ability to satisfy the covenants in the General Gas Works Revenue Bond Ordinance of 1998 authorizing the issuance of the Bonds; and (f) information regarding potential liquefied natural gas ("LNG") expansion opportunities.

Puget Sound Energy (2013 – 2014)

Engaged to perform a review of its project management and capital spending authorization processes (CSA). The overall project objectives were to educate project management (PM) staff as to the importance and relevance of regulatory prudence standards, evaluate existing PM processes along with newly introduced corporate CSA processes, and propose PM and corporate process and documentation efficiencies. This task was accomplished through 1) a situational assessment and risk review; 2) analysis of project management practices; and 3) development of common documentation for the CSA and PM processes.

Puget Sound Energy (2012 – 2013)

Engaged to perform a review of how the company compares to similarly situated utilities in the areas of the underlying capitalized costs related to new customer additions ("new business investment") and the management policies and practices that influence the new business capital investment. Examined the interrelationships of our client's management policies and practices in the functional areas related to new business investment and developed an understanding of the nature of the costs captured by the new business investment process. Benchmarked those costs relative to peers' cost factors and management capital expenditure practices and performed targeted peer group interviews on our client's behalf. The review identified certain trends and/or interrelationships between management policies and practices, as well as other exogenous factors, and the resulting impact on new business investment.

Puget Sound Energy (2011 – 2012)

Engaged to perform a review of its electric transmission planning and project prioritization process. The emphasis of the review was to determine if the process implemented by the client could be expected to meet the regulatory standard of prudence, as adopted by the state regulatory commission. Reviewed the prudence standard adopted by the commission in several recent regulatory proceedings, supplemented by our knowledge of the prudence standard adopted at a national level and in other states. The engagement included two phases: 1) an initial situation assessment of the existing process employed by the client, and 2) a review of the historic implementation of that process by reviewing a sampling of transmission projects. Compiled and provided examples of capital planning documents and procedures, viewed as "best practices," from other electric utilities and other relevant transmission entities.

Alliant Energy (2011 – 2012)

Provided audit support for one of the company's gas and electric utilities, Interstate Power & Light, during a management audit ordered by one of its two regulatory jurisdictions. Conducted a pre-audit of distribution operations and resource planning processes to provide the client with potential audit issues. Assisted the client throughout the audit process in responding to information requests, preparing company executives and management personnel for audit interviews, and management of preliminary audit issues and findings by the independent audit firm.

Ameren Illinois Utilities (2009 – 2010)

Performed a number of benchmark analyses to compare each of the client's A&G and O&M expenses, on a per-customer basis, to various peer groups conducted for the client's natural gas and electric operations. Analyses were performed for natural gas, electric and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Served as an expert witness on behalf of the client in a consolidated general rate case proceeding of its three utility subsidiaries before the Illinois Commerce Commission.

EXPERT WITNESS TESTIMONY PRESENTATION

- Alaska Regulatory Commission
- Arkansas Public Service Commission
- British Columbia Utility Commission (Canada)
- Colorado Public Utility Commission
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Kansas Corporation Commission
- Massachusetts Department of Utilities
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- Montana Public Service Commission
- New Brunswick Energy and Utilities Board (Canada)
- North Dakota Public Service Commission
- Oklahoma Corporation Commission
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- Washington Utilities and Transportation Commission
- Federal Energy Regulatory Commission

SELECTED PUBLICATIONS / PRESENTATIONS

"Enhancing the Profitability of Growth," American Gas Association, Rate and Regulatory Issues Seminar, April 4 - 7, 2004

"Regulatory Treatment of New Generation Resource Acquisition: Key Aspects of Resource Policy, Procurement and New Resource Acquisition," Law Seminars International, Managing the Modern Utility Rate Case, February 17 - 18, 2005

"Managing Regulatory Risk – The Risk Associated with Uncertain Regulatory Outcomes,"

Western Energy Institute, Spring Energy Management Meeting, May 18 - 20, 2005

"Capital Asset Optimization – An Integrated Approach to Optimizing Utilization and Return on Utility Assets," Southern Gas Association, July 18 - 20, 2005

"Resource Planning as a Cost Recovery Tool," Law Seminars International, Utility Rate Case Issues & Strategies, February 22 - 23, 2007

"Natural Gas Infrastructure Development and Regulatory Challenges," Southeastern Association of Regulatory Utility Commissioners, Annual Conference, June 4 – 6, 2007

"Resource Planning in a Changing Regulatory Environment," Law Seminars International, Utility Rate Cases – Current Issues & Strategies, February 7 - 8, 2008

"Natural Gas Distribution Infrastructure Replacement," American Gas Association, Rate Committee Meeting and Regulatory Issues Seminar, April 11 – 13, 2010

"Building a T&D Investment Program to Satisfy Customers, Regulators and Shareholders," SNL Webinar, March 27, 2014

"Utility Infrastructure Replacement; Trends in Aging Infrastructure, Replacement Programs and Rate Treatment," Large Public Power Council, Rates Committee Meeting, August 14, 2014

"Natural Gas in the Decarbonization Era, Gas Resource Planning for Electric Generation," EUCI, January 22-23, 2020

Unitil NH - Electric Division
12 Months Ended December 31, 2020
Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY	ACCOUNT BALANCE	D - Domestic Delivery Service	G2 - Regular General Service	G1 - Large General Service	Outdoor Lighting
1	**Rate Base**					
2	Plant in Service	407,914,122	286,045,852	79,128,205	34,863,113	7,876,951
3	Accumulated Reserve	(138,059,087)	(97,321,043)	(26,485,481)	(9,931,826)	(4,320,737)
4	Other Rate Base Items	(43,824,954)	(30,663,230)	(8,604,323)	(3,718,307)	(839,094)
5	Total Rate Base	226,030,081	158,061,579	44,038,401	21,212,979	2,717,121
6	**Total Revenue at Current Rates**					
7	Total Distribution Margin	58,056,553	31,580,284	16,916,360	7,736,414	1,823,495
8	Late Payment Charges (450)	275,537	249,040	21,925	3,573	999
9	Misc. Service Revenues (451)	194,996	137,978	37,091	16,096	3,831
10	Rent-elect. Property (454)	585,200	410,366	113,519	50,015	11,300
11	Other Electric Rev (456)	143,733	101,704	27,340	11,864	2,824
12	New DOC Rent Revenue	313,007	221,481	59,539	25,837	6,150
13	Total Revenue	59,569,025	32,700,853	17,175,775	7,843,798	1,848,599
14	**Expenses at Current Rates**					
15	O&M and A&G Expenses	26,051,337	18,853,556	4,658,497	1,765,392	773,892
16	Other Power Generation Expense	284,252	126,390	77,665	78,329	1,868
17	Depreciation and Amortization Expense	14,241,708	9,971,023	2,848,036	1,227,802	194,847
18	Taxes Other Than Income	8,072,185	5,663,185	1,563,956	685,135	159,909
19	Income Taxes	1,852,866	(324,656)	1,362,155	693,520	121,847
20	Total Expenses - Current	50,502,348	34,289,498	10,510,309	4,450,179	1,252,362
21	Operating Income - Current	9,066,677	(1,588,645)	6,665,466	3,393,620	596,237
22	Current Rate of Return	4.01%	-1.01%	15.14%	16.00%	21.94%
23	**Present Revenue at Equal Rates of Return**					
24	Present Return	4.01%	4.01%	4.01%	4.01%	4.01%
25	Present Operating Income @ Equal Return	9,066,677	6,340,277	1,766,499	850,910	108,991
26	Income Taxes	1,852,866	1,295,699	361,002	173,892	22,273
27	Other Expenses	48,649,481	34,614,153	9,148,154	3,756,659	1,130,515
28	Total Revenue @ Equal Rates of Return	59,569,025	42,250,129	11,275,656	4,781,461	1,261,780
29	Present (Subsidies)/Excesses	-	(9,549,277)	5,900,119	3,062,338	586,820

Unitil NH - Electric Division
12 Months Ended December 31, 2020
Summary of Cost of Service Study Results

	REVENUE REQUIREMENT SUMMARY	ACCOUNT BALANCE	D - Domestic Delivery Service	G2 - Regular General Service	G1 - Large General Service	Outdoor Lighting
30	**Revenue Requirement at Equal Rates of Return**					
31	Required Return	7.88%	7.88%	7.88%	7.88%	7.88%
32	Required Operating Income	17,811,170	12,455,252	3,470,226	1,671,583	214,109
33	**Expenses at Required Return**					
34	O&M and A&G Expenses	26,051,337	18,853,556	4,658,497	1,765,392	773,892
35	Other Power Generation Expense	284,252	126,390	77,665	78,329	1,868
36	Depreciation and Amortization Expense	14,241,708	9,971,023	2,848,036	1,227,802	194,847
37	Taxes Other Than Income	8,072,185	5,663,185	1,563,956	685,135	159,909
38	Income Taxes	1,852,866	1,295,699	361,002	173,892	22,273
39	Gross Up - Income Taxes	3,247,900	2,271,238	632,802	304,816	39,043
40	Gross Up - Gross Receipts & Uncollectibles	-	-	-	-	-
41	Total Expenses - Required	53,750,248	38,181,091	10,141,958	4,235,367	1,191,832
42	Total Revenue Requirement at Equal Return	71,561,418	50,636,343	13,612,184	5,906,950	1,405,941
43	Current Miscellaneous Revenue	1,512,473	1,120,569	259,415	107,385	25,104
44	Total Revenue @ Equal Rates of Return	70,048,945	49,515,774	13,352,769	5,799,565	1,380,837
45	Revenue (Deficiency)/Surplus	(11,992,393)	(17,935,490)	3,563,590	1,936,849	442,658
46	Total Base Revenue as Proposed	70,048,945	41,026,489	18,663,515	8,535,446	1,823,495
47	Miscellaneous Revenue	1,512,473	1,120,569	259,415	107,385	25,104
48	Total Revenue as Proposed	71,561,418	42,147,058	18,922,930	8,642,831	1,848,599
49	Total Distribution Margin Increase as Proposed	11,992,393	9,446,205	1,747,155	799,032	-
50	Miscellaneous Revenues Change	-	-	-	-	-
51	Total Revenue Increase as Proposed	11,992,393	9,446,205	1,747,155	799,032	-
52	Precent Base Revenue Change (Line 51/Line 7)	20.13%	29.91%	10.33%	10.33%	0.00%
53	Income Prior to Taxes	22,911,936	7,532,905	9,774,776	4,886,172	718,084
54	Income Taxes	5,100,766	1,677,012	2,176,108	1,087,783	159,863
55	Operating Income	17,811,170	5,855,893	7,598,668	3,798,389	558,221
56	**Proposed Return**	7.88%	3.70%	17.25%	17.91%	20.54%

Docket No. DE 21-030
Schedule RJA-3
Proposed Revenue Allocation by Class
Page 1 of 1

Unitil NH - Electric Division
12 Months Ended December 31, 2020

Proposed Revenues
Revenue Apportionment

		Total Company	D - Domestic Delivery Service	G2 - Regular General Service	G1 - Large General Service	Outdoor Lighting
1	**Current Margin Revenue**	58,056,553	31,580,284	16,916,360	7,736,414	1,823,495
2	**Revenue to Cost Ratio Under Current Rates**	0.83	0.64	1.27	1.33	1.32
3	**Revenues at Equalized Rates of Return**					
4	Revenue Increase	11,992,393	17,935,490	(3,563,590)	(1,936,849)	(442,658)
5	Total revenue at equalized rates of return	70,048,945	49,515,774	13,352,769	5,799,565	1,380,837
6	Percent Increase	20.66%	56.79%	(21.07%)	(25.04%)	(24.28%)
7	Parity Ratio	1.00	1.00	1.00	1.00	1.00
8	**Secnario A: Equal Percentage Increase**					
9	Revenue Increase	11,992,393	6,523,349	3,494,311	1,598,064	376,668
10	Total revenue at equal percentage increase	70,048,945	38,103,633	20,410,670	9,334,478	2,200,164
11	Percent Increase	20.66%	20.66%	20.66%	20.66%	20.66%
12	Parity Ratio	1.00	0.77	1.53	1.61	1.59
13	**Secnario B: No Class Increase Above Parity**					
14	Revenue Increase	11,992,393	11,992,393	0	0	0
15	Total revenue with no increase to classes above parity	70,048,945	43,572,677	16,916,360	7,736,414	1,823,495
16	Percent Increase	20.66%	37.97%	0.00%	0.00%	0.00%
17	Parity Ratio	1.00	0.88	1.27	1.33	1.32
18	**Secnario C: Minimum Class Increase of 50% of System Average**					
19	Minimum 50% of system average increase		145%	50%	50%	0%
20	Revenue Increase	11,992,393	9,446,205	1,747,155	799,032	0
21	Total revenue at 25% system average minimum	70,048,945	41,026,489	18,663,515	8,535,446	1,823,495
22	Percent Increase	20.66%	29.91%	10.33%	10.33%	0.00%
23	Parity Ratio	1.00	0.83	1.40	1.47	1.32

Docket No. DE 21-030
Schedule RJA-4
ACOSS Unit Cost Report
Page 1 of 3

Unitil NH - Electric Division
12 Months Ended December 31, 2020

Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL RATE BASE	D - Domestic Delivery Service	G2 - Regular General Service	G1 - Large General Service	Outdoor Lighting
	Functional Rate Base					
1	**Electric Procurement Supply**					
2	Demand	$ 13,797	$ 7,216	$ 3,637	$ 2,944	$ -
3	Energy	$ 687,195	$ 305,554	$ 187,760	$ 189,365	$ 4,516
4	Customer	$ -	$ -	$ -	$ -	$ -
5	Subtotal	$ 700,992	$ 312,771	$ 191,397	$ 192,309	$ 4,516
6	**Radial Transmission**					
7	Demand	$ 206,652	$ 111,284	$ 50,295	$ 43,653	$ 1,420
8	Energy	$ -	$ -	$ -	$ -	$ -
9	Customer	$ -	$ -	$ -	$ -	$ -
10	Subtotal	$ 206,652	$ 111,284	$ 50,295	$ 43,653	$ 1,420
11	**Distribution Sub-Transmission**					
12	Demand	$ 38,899,578	$ 20,947,864	$ 9,467,411	$ 8,217,073	$ 267,230
13	Energy	$ -	$ -	$ -	$ -	$ -
14	Customer	$ -	$ -	$ -	$ -	$ -
15	Subtotal	$ 38,899,578	$ 20,947,864	$ 9,467,411	$ 8,217,073	$ 267,230
16	**Distribution Primary**					
17	Demand	$ 49,191,543	$ 26,490,204	$ 11,972,277	$ 10,391,128	$ 337,933
18	Energy	$ -	$ -	$ -	$ -	$ -
19	Customer	$ 53,279,692	$ 45,152,087	$ 7,440,286	$ 111,319	$ 576,001
20	Subtotal	$ 102,471,235	$ 71,642,291	$ 19,412,563	$ 10,502,447	$ 913,934
21	**Distribution Secondary**					
22	Demand	$ 21,364,641	$ 15,028,715	$ 4,280,211	$ 1,970,355	$ 85,361
23	Energy	$ -	$ -	$ -	$ -	$ -
24	Customer	$ 31,732,680	$ 26,523,290	$ 4,866,892	$ 49,153	$ 293,345
25	Subtotal	$ 53,097,322	$ 41,552,005	$ 9,147,103	$ 2,019,508	$ 378,706
26	**Onsite & Metering**					
27	Demand	$ -	$ -	$ -	$ -	$ -
28	Energy	$ -	$ -	$ -	$ -	$ -
29	Customer	$ 17,245,355	$ 12,107,537	$ 4,036,630	$ 213,948	$ 887,241
30	Subtotal	$ 17,245,355	$ 12,107,537	$ 4,036,630	$ 213,948	$ 887,241
31	**Customer Accounts & Service**					
32	Demand	$ -	$ -	$ -	$ -	$ -
33	Energy	$ -	$ -	$ -	$ -	$ -
34	Customer	$ 13,408,947	$ 11,387,828	$ 1,733,003	$ 24,041	$ 264,075
35	Subtotal	$ 13,408,947	$ 11,387,828	$ 1,733,003	$ 24,041	$ 264,075
36	**Total**					
37	Demand	$ 109,676,211	$ 62,585,284	$ 25,773,831	$ 20,625,153	$ 691,943
38	Energy	$ 687,195	$ 305,554	$ 187,760	$ 189,365	$ 4,516
39	Customer	$ 115,666,675	$ 95,170,741	$ 18,076,811	$ 398,461	$ 2,020,661
40	**Total Rate Base**	$ 226,030,081	$ 158,061,579	$ 44,038,401	$ 21,212,979	$ 2,717,121

Unitil NH - Electric Division
12 Months Ended December 31, 2020

Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description		TOTAL		D - Domestic Delivery Service		G2 - Regular General Service		G1 - Large General Service		Outdoor Lighting
	Functional Revenue Requirement										
41	**Electric Procurement Supply**										
41	Demand	$	13,322	$	6,968	$	3,512	$	2,843	$	-
42	Energy	$	671,094	$	298,395	$	183,361	$	184,928	$	4,410
42	Customer	$	-	$	-	$	-	$	-	$	-
43	Subtotal	$	684,417	$	305,363	$	186,872	$	187,771	$	4,410
44	**Radial Transmission**										
44	Demand	$	183,848	$	99,004	$	44,745	$	38,836	$	1,263
45	Energy	$	-	$	-	$	-	$	-	$	-
45	Customer	$	-	$	-	$	-	$	-	$	-
46	Subtotal	$	183,848	$	99,004	$	44,745	$	38,836	$	1,263
47	**Distribution Sub-Transmission**										
47	Demand	$	7,919,614	$	4,264,802	$	1,927,482	$	1,672,924	$	54,406
48	Energy	$	-	$	-	$	-	$	-	$	-
48	Customer	$	-	$	-	$	-	$	-	$	-
49	Subtotal	$	7,919,614	$	4,264,802	$	1,927,482	$	1,672,924	$	54,406
50	**Distribution Primary**										
51	Demand	$	15,496,200	$	8,344,880	$	3,771,478	$	3,273,388	$	106,455
52	Energy	$	-	$	-	$	-	$	-	$	-
53	Customer	$	16,732,641	$	14,180,143	$	2,336,643	$	34,960	$	180,895
54	Subtotal	$	32,228,841	$	22,525,022	$	6,108,121	$	3,308,348	$	287,350
55	**Distribution Secondary**										
56	Demand	$	4,724,920	$	3,323,691	$	946,595	$	435,756	$	18,878
57	Energy	$	-	$	-	$	-	$	-	$	-
58	Customer	$	8,347,837	$	6,934,418	$	1,329,335	$	12,469	$	71,615
59	Subtotal	$	13,072,757	$	10,258,110	$	2,275,929	$	448,225	$	90,493
60	**Onsite & Metering**										
61	Demand	$	-	$	-	$	-	$	-	$	-
62	Energy	$	-	$	-	$	-	$	-	$	-
63	Customer	$	8,033,403	$	5,346,092	$	1,782,377	$	94,469	$	810,466
64	Subtotal	$	8,033,403	$	5,346,092	$	1,782,377	$	94,469	$	810,466
65	**Customer Accounts & Service**										
66	Demand	$	-	$	-	$	-	$	-	$	-
67	Energy	$	-	$	-	$	-	$	-	$	-
68	Customer	$	9,438,538	$	7,837,949	$	1,286,658	$	156,377	$	157,553
69	Subtotal	$	9,438,538	$	7,837,949	$	1,286,658	$	156,377	$	157,553
70	**Total**										
71	Demand	$	28,337,905	$	16,039,345	$	6,693,811	$	5,423,747	$	181,002
72	Energy	$	671,094	$	298,395	$	183,361	$	184,928	$	4,410
73	Customer	$	42,552,419	$	34,298,602	$	6,735,013	$	298,275	$	1,220,529
74	**Total Revenue Requirement**	$	71,561,418	$	50,636,343	$	13,612,184	$	5,906,950	$	1,405,941
75	Demand		39.60%		31.68%		49.18%		91.82%		12.87%
76	Energy		0.94%		0.59%		1.35%		3.13%		0.31%
77	Customer		59.46%		67.74%		49.48%		5.05%		86.81%

Docket No. DE 21-030
Schedule RJA-4
ACOSS Unit Cost Report
Page 3 of 3

Unitil NH - Electric Division
12 Months Ended December 31, 2020

Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	D - Domestic Delivery Service	G2 - Regular General Service	G1 - Large General Service	Outdoor Lighting
	Unit Costs					
78	**Electric Procurement Supply**					
79	Demand	$ 0.05	$ 0.04	$ 0.05	$ 0.05	$ -
80	Energy	$ 0.5783	$ 0.5783	$ 0.5783	$ 0.5783	$ 0.5783
81	Customer	$ -	$ -	$ -	$ -	$ -
82	**Radial Transmission**					
83	Demand	$ 0.63	$ 0.63	$ 0.63	$ 0.62	$ 0.63
84	Energy	$ -	$ -	$ -	$ -	$ -
85	Customer	$ -	$ -	$ -	$ -	$ -
86	**Distribution Sub-Transmission**					
87	Demand	$ 26.93	$ 26.99	$ 26.98	$ 26.73	$ 26.99
88	Energy	$ -	$ -	$ -	$ -	$ -
89	Customer	$ -	$ -	$ -	$ -	$ -
90	**Distribution Primary**					
91	Demand	$ 52.69	$ 52.80	$ 52.79	$ 52.30	$ 52.80
92	Energy	$ -	$ -	$ -	$ -	$ -
93	Customer	$ 15.78	$ 17.39	$ 17.39	$ 17.39	$ 1.67
94	**Distribution Secondary**					
95	Demand	$ 16.07	$ 21.03	$ 13.25	$ 6.96	$ 9.36
96	Energy	$ -	$ -	$ -	$ -	$ -
97	Customer	$ 7.87	$ 8.51	$ 9.90	$ 6.20	$ 0.66
98	**Onsite & Metering**					
99	Demand	$ -	$ -	$ -	$ -	$ -
100	Energy	$ -	$ -	$ -	$ -	$ -
101	Customer	$ 7.58	$ 6.56	$ 13.27	$ 47.00	$ 7.46
102	**Customer Accounts & Service**					
103	Demand	$ -	$ -	$ -	$ -	$ -
104	Energy	$ -	$ -	$ -	$ -	$ -
105	Customer	$ 8.90	$ 9.61	$ 9.58	$ 77.80	$ 1.45
106	**TOTAL**					
107	Demand (per kW)	$ 96.36	$ 101.49	$ 93.70	$ 86.66	$ 89.78
108	Energy (per kWh)	$ 0.57832	$ 0.57832	$ 0.57832	$ 0.57832	$ 0.57832
109	Customer (per cust month)	$ 40.13	$ 42.07	$ 50.13	$ 148.40	$ 11.24
110	Demand & Customer (per cust mo.)	$ 66.86	$ 61.74	$ 99.96	$ 2,846.78	$ 12.91
111	**BILLING DETERMINANTS**					
112	Demand (kW)	294,079	158,032	71,441	62,590	2,016
113	Energy (kWh)	1,160,419	515,969	317,057	319,767	7,626
114	Customer Bills	1,060,234	815,280	134,344	2,010	108,600

Unitil Energy Systems, Inc.

External Class Allocation Factors Summary

Line No.	Name	Description	Total	D - Domestic Delivery Service	G2 - Regular General Service	G1 - Large General Service	Outdoor Lighting
1	**DEMAND ALLOCATORS**						
2	CP @ Supply						
3		Coincident Peaks @ Generation	286,670	149,935	75,569	61,167	-
4		Adjustment Factor		100%	100%	100%	100%
5	CP_DEMAND	CP Demand Allocator	286,670	149,935	75,569	61,167	-
6			100%	52.30%	26.36%	21.34%	0.00%
7	NCPs @ Supply						
8		NCPs @ Generation	311,871	168,254	76,007	65,464	2,146
9		Adjustment Factor		100%	100%	100%	100%
10	PROCURE_DEMAND	Supply Demand Allocator	311,871	168,254	76,007	65,464	2,146
11			100%	53.95%	24.37%	20.99%	0.69%
12	NCPs @ Sub-Transmission						
13		NCPs @ Sub-Transmission	308,811	166,603	75,261	64,821	2,125
14		Adjustment Factor		100%	100%	100%	100%
15	SUB-TRANS_DEMAND	Sub-Transmission Demand Allocator	308,811	166,603	75,261	64,821	2,125
16			100%	53.95%	24.37%	20.99%	0.69%
17	NCPs @ Primary						
18		NCPs @ Primary	301,451	162,335	73,367	63,678	2,071
19		Adjustment Factor		100%	100%	100%	100%
20	PRI_DEMAND	Primary Demand Allocator	301,451	162,335	73,367	63,678	2,071
21			100%	53.85%	24.34%	21.12%	0.69%
22	NCPs @ Secondary						
23		Max Customer NCPs @ Secondary	504,576	354,939	101,087	46,535	2,016
24		Adjustment Factor		100%	100%	100%	100%
25	SEC_DEMAND	Secondary Demand Allocator	504,576	354,939	101,087	46,535	2,016
26			100%	70.34%	20.03%	9.22%	0.40%
27	NCPs @ Meter						
28		Metered NCPs	294,079	158,032	71,441	62,590	2,016
29		Adjustment Factor		100%	100%	100%	100%
30	METERED_DEMAND	Metered Demand Allocator	294,079	158,032	71,441	62,590	2,016
31			100%	53.74%	24.29%	21.28%	0.69%

Unitil Energy Systems, Inc.

External Class Allocation Factors Summary

Line No.	Name	Description	Total	D - Domestic Delivery Service	G2 - Regular General Service	G1 - Large General Service	Outdoor Lighting
32	**CUSTOMER ALLOCATORS**						
33	Customer Count - billing						
34	CUSTOMERS	Test Year 2020 Customer Count	80,852	67,940	11,195	168	1,549
35			100%	84.03%	13.85%	0.21%	1.92%
36	Number of Customers Using Primary System						
37	PRI_CUST	Test Year 2020 Customer Count	80,169	67,940	11,195	168	867
38			100%	84.75%	13.96%	0.21%	1.08%
39	Number of Customers Using Secondary System						
40	SEC_CUST	Test Year 2020 Customer Count	80,116	67,940	11,175	135	867
41			100%	84.80%	13.95%	0.17%	1.08%
42	Number of Customers Billed at Primary Voltage						
43	LARGE_CUST	Test Year 2020 Customer Count	53	-	21	33	-
44			100%	0.00%	38.38%	61.62%	0.00%
45	Number of Customers and Light Fixtures						
46	ONSITE_CUST	Test Year 2020 Customer Count	88,353	67,940	11,195	168	9,050
47			100%	76.90%	12.67%	0.19%	10.24%
48	Allocation of Meter Investments						
49		Average Cost per Meter		$ 356.53	$ 721.36	$ 2,555.42	$ -
50		Relative Weighting Factor		1.00	2.02	7.17	-
51	METERS	Weighted Meter Count	91,792	67,940	22,651	1,201	-
52			100%	74.02%	24.68%	1.31%	0.00%
53	Allocation of Services						
54		Service Cost per Service		$ 708.28	$ 1,321.35	$ 293.31	$ -
55		Relative Weighting Factor		1.00	1.87	0.41	-
56	SERVICES	Weighted Customers	88,895	67,940	20,886	69	-
57			100%	76.43%	23.49%	0.08%	0.00%
58	Uncollectible						
59	UNCOLLECT	Uncollectibles	$ 972,322	$ 878,816	$ 77,371	$ 12,608	$ 3,527
60			100%	90.38%	7.96%	1.30%	0.36%
61	Customer Deposits						
62	CUST_DEPOSITS	Customer Deposits	$ 371,830	$ 192,145	$ 175,177	$ 4,508	$ -
63			100%	51.68%	47.11%	1.21%	0.00%

Docket No. DE 21-030
Schedule RJA-5
Summary of ACOSS External Allocation Factors
Page 3 of 3

Unitil Energy Systems, Inc.

External Class Allocation Factors Summary

Line No.	Name	Description	Total	D - Domestic Delivery Service	G2 - Regular General Service	G1 - Large General Service	Outdoor Lighting
64	Meter Reading						
65	ACCT_902	Meter Reading	$ 63,751	$ 47,185	$ 15,732	$ 834	$ -
66			100%	74.02%	24.68%	1.31%	0.00%
67	Cutomer Records and Collections						
68	ACCT_903	Cutomer Records and Collections	$ 3,226,861	$ 2,723,565	$ 442,139	$ 7,584	$ 53,573
69			100%	84.40%	13.70%	0.24%	1.66%
70	Customer Assistance						
71	ACCT_909	Customer Assistance	$ 28,775	$ 24,897	$ 3,362	$ 50	$ 465
72			100%	86.52%	11.68%	0.17%	1.62%
73	Direct Assignment of Lighting						
74	LIGHT		1	-	-	-	1
75			100%	0.00%	0.00%	0.00%	100.00%
76	**ENERGY ALLOCATORS**						
77	MWh Sales						
78	ENERGY	MWh Sales	1,160,419	515,969	317,057	319,767	7,626
79			100.00%	44.46%	27.32%	27.56%	0.66%
80	**REVENUE ALLOCATORS**						
81	Distribution Revenue						
82	DIST_REVENUE	Total Revenue	58,056,553	31,580,284	16,916,360	7,736,414	1,823,495
83			100%	54.40%	29.14%	13.33%	3.14%
84	***FUNCTIONAL PLANT ALLOCATORS***						
85	Misc. Intangible Plant Split						
86	Plant Related	Account 303 related to plant	2.90%				
87	Customer Related	Account 303 related to billing, meter reading, customer accounts	66.81%				
88	Labor Related	Account 303 related to operations, IT, finance accounting, employees	30.28%				

Unitil Energy Systems, Inc.

Description of ACOSS Functionalization and Classification of Accounts

FERC	Description	Functionalization	Classification
Intangible Plant			
301-303	Intangible Plant		
301	Organization	Labor expense	Labor expense
303	Miscellaneous Intangible Plant, Plant-related	Total plant in service	Total plant in service
303	Miscellaneous Intangible Plant, Customer-related	Accounts & Services	Customer-related
303	Miscellaneous Intangible Plant, Labor-related	Labor expense	Labor expense
Production Plant and Expenses			
340-348	Other Production Plant		
343	Prime Movers	Supply	Demand-related
555-557	Other Power Generation Expense		
555	Purchased Power Expenses	Supply	Energy-related
557	Other Purchased Power	Supply	Energy-related
Transmission Plant and Expenses			
350-359	Transmission Plant	No transmission plant	N/A
560-571	Transmission Expenses		
560	Supervision and Engineering	Transmission	Demand-related
562	Station Expenses	Transmission	Demand-related
563	Overhead Line Expenses	Transmission	Demand-related
567	Rents	Transmission	Demand-related
568	Supervision and Engineering	Transmission	Demand-related
571	Maintenance of Overhead Lines	Transmission	Demand-related

FERC	Description	Functionalization	Classification
Distribution Plant and Expenses			
360-373	*Distribution Plant*		
360	Land and Land Rights	Accounts 361 through 364	Accounts 361 through 364
361	Structures and Improvements	Sub-transmission	Demand-related
362	Station Equipment	Sub-transmission	Demand-related
364	Poles, Towers and Fixtures - Primary	Primary distribution	Demand-Customer split based on the minimum system analysis
364	Poles, Towers and Fixtures - Secondary	Secondary distribution	Demand-Customer split based on the minimum system analysis
365	Overhead Conductors and Devices - Primary	Primary distribution	Demand-Customer split based on the minimum system analysis
365	Overhead Conductors and Devices - Secondary	Secondary distribution	Demand-Customer split based on the minimum system analysis
366	Underground Conduit - Primary	Primary distribution	Demand-Customer split based on the minimum system analysis
366	Underground Conduit - Secondary	Secondary distribution	Demand-Customer split based on the minimum system analysis
367	Underground Conductors and Devices - Primary	Primary distribution	Demand-Customer split based on the minimum system analysis
367	Underground Conductors and Devices - Secondary	Secondary distribution	Demand-Customer split based on the minimum system analysis
368	Line Transformers	Line transformers	Demand-Customer split based on the minimum system analysis
368.1	Line Transformer Installations	Line transformers	Demand-Customer split based on the minimum system analysis
369	Services	Secondary distribution	Customer-related
370	Meters	Onsite	Customer-related

FERC	Description	Functionalization	Classification
370.1	Meter Installations	Onsite	Customer-related
371	Installations on Cust Premises	Onsite	Customer-related
373	Street Lighting and Signal Systems	Onsite	Customer-related
580-598	*Distribution Expenses*		
580	Operation Supervision & Engineering	Accounts 582-589	Accounts 582-589
581	Load Dispatching	Accounts 582-589	Accounts 582-589
582	Station Expenses	Sub-transmission	Demand-related
583	Overhead Line Expenses	Account 365	Account 365
584	Underground Line Expenses	Account 367	Account 367
585	Street Lighting and Signal Systems	Onsite	Customer-related
586	Meter Expenses	Onsite	Customer-related
587	Customer Installation Expenses	Onsite	Customer-related
588	Misc. Distribution Expenses	Distribution plant	Distribution plant
589	Rents	Distribution plant	Distribution plant
590	Maintenance Supervision & Engineering	Accounts 591-598	Accounts 591-598
591	Maintenance of Structures	Sub-transmission	Demand-related
592	Maintenance of Station Equipment	Sub-transmission	Demand-related
593	Maintenance of Overhead Lines	Account 365	Account 365
594	Maintenance of Underground Lines	Account 367	Account 367
595	Maintenance of Line Transformers	Account 368	Account 368
596	Maintenance of Street Lights	Onsite	Customer-related
597	Maintenance of Meters	Onsite	Customer-related
598	Maintenance of Misc. Plant	Distribution plant	Distribution plant
General Plant			
389-399	General & Common Plant	Labor expense	Labor expense

FERC	Description	Functionalization	Classification
Depreciation Reserve			
108	Accumulated Depreciation	Corresponding plant accts.	Corresponding plant accts.
Other Rate Base Items			
165	Prepayments	Total plant in service	Total plant in service
131	Cash Working Capital	Total plant in service	Total plant in service
154	Materials and Supplies	Total plant in service	Total plant in service
182, 254	Regulatory Assets	Total plant in service	Total plant in service
235	Customer Deposits	Accounts & Services	Customer-related
190	Net Deferred Income Taxes	Total plant in service	Total plant in service
	Excess Deferred Income Taxes	Total plant in service	Total plant in service
	Deferred Income Taxes Debit	Total plant in service	Total plant in service
Customer Expenses			
901-905	Customer Accounts Expense	Accounts & Services	Customer-related
906-910	Customer Service & Information Expense	Accounts & Services	Customer-related
911-917	Sales Expense	N/A	N/A
Administrative and General Expenses			
920	Administrative & General Salaries	Labor expense	Labor expense
921	Office Supplies & Expenses	Labor expense	Labor expense
923	Outside Services Employed	Labor expense	Labor expense
923-D	Key Account Management	Accounts & Services	Customer-related
926	Employee Pensions and Benefits	Labor expense	Labor expense
924	Property Insurance	Total plant in service	Total plant in service
925	Injuries and Damages	Total plant in service	Total plant in service
935	Maintenance of General Plant	Total plant in service	Total plant in service
927	Franchise Requirements	O&M expense allocation	O&M expense allocation

FERC	Description	Functionalization	Classification
928	Regulatory Commission Expenses	O&M expense allocation	O&M expense allocation
930	General/Miscellaneous. Expenses	O&M expense allocation	O&M expense allocation
931	Rents	O&M expense allocation	O&M expense allocation
	Test year Inflation Allowance	O&M expense allocation	O&M expense allocation
Depreciation and Amortization Expenses			
403	Depreciation Expense	Accumulated depreciation	Accumulated depreciation
404-407	Amortization Expense	Total plant in service	Total plant in service
Taxes Other Than Income			
408	Payroll Taxes	Labor expense	Labor expense
408	Unemployment Tax	Labor expense	Labor expense
408	Property Taxes	Total plant in service	Total plant in service
408	NH BET Taxes	Total plant in service	Total plant in service
408	NH Surcharge Taxes	Total plant in service	Total plant in service
Income Taxes			
409-410	Income Taxes	Rate base	Rate base
Revenues			
440-449	Distribution Revenue	Revenue requirement	Revenue requirement
454	Rent from Electric Property	Total plant in service	Total plant in service
450-457	All Other Revenues	Revenue requirement	Revenue requirement

Docket No. DE 21-030
Schedule RJA-7
Minimum System Study Results
Page 1 of 1

UNITIL ENERGY SYSTEMS, INC.

SUBFUNCTIONALIZATION/CLASSIFICATION OF DISTRIBUTION PLANT

SUMMARY OF RESULTS

FOR COST ALLOCATION PURPOSES

		FUNCTIONALIZATION		PRIMARY SPLIT		SECONDARY SPLIT	
DIST. ACCT. NO.	DESCRIPTION	PRIMARY % OF ACCOUNT TOTAL	SECONDARY % OF ACCOUNT TOTAL	CUSTOMER COMPONENT % OF	DEMAND COMPONENT % OF	CUSTOMER COMPONENT % OF	DEMAND COMPONENT % OF
364	POLES, TOWERS AND FIXTURES	84.32%	15.68%	45.45%	54.55%	46.21%	53.79%
365	OVERHEAD CONDUCTORS AND DEVICES	84.59%	15.41%	50.98%	49.02%	70.80%	29.20%
367	UNDERGROUND CONDUCTORS	93.46%	6.54%	69.31%	30.69%	35.73%	64.27%
368	TRANSFORMERS	0.00%	100.00%	NA	NA	54.14%	45.86%

UES Minimum Size System Study

Primary

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
			Minimum Size			Expand to Total Account				
Account	Minimum Size (Asset Description)	Unit	Total Installed Cost	Total Installed Units	Average Unit Cost (4)/(5)	Total Units	Total Customer Component	Account Total	% Customer (8)/(9)	% Demand 100-(10)
364	30 FOOT	Pole			$ 530.96	48,517	$ 25,760,813	$ 56,678,749	**45.45%**	**54.55%**
365	365-00/ 31/2 : #6 WIRE	Feet	$ 5,896,066	2,475,090	$ 2.38	19,113,164	$ 45,530,657	$ 89,315,929	**50.98%**	**49.02%**
367	367-00/ 8/2 : #2 URD CABLE	Feet	$ 1,561,231	255,636	$ 6.11	2,918,153	$ 17,821,863	$ 25,714,356	**69.31%**	**30.69%**

Secondary

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
			Minimum Size			Expand to Total Account				
Account	Minimum Size (Asset Description)	Unit	Total Installed Cost	Total Installed Units	Average Unit Cost (4)/(5)	Total Units	Total Customer Component	Account Total	% Customer (8)/(9)	% Demand 100-(10)
364	30 FOOT	Pole			$ 530.96	9,095	$ 4,829,087	$ 10,451,423	**46.21%**	**53.79%**
365	365-00/ 70/2 : #4 TRIPLEX (3W #4)	Feet	$ 233,330	42,022	$ 5.55	3,583,740	$ 19,898,940	$ 28,105,481	**70.80%**	**29.20%**
367	367-00/ 49/2 : #500 MCM	Feet	$ 35,711	11,214	$ 3.18	21,853	$ 69,590	$ 194,770	**35.73%**	**64.27%**
368 Material	368-00/ 68/2 : 15 KVA	KVA	$ 10,756,584	4,622	$ 2,327.26	22,980	$ 53,480,374	$ 93,399,648	57.26%	42.74%
368 Install	368-01/ 2/2 : 10-25 KVA INSTALL	KVA	$ 3,152,146	4,077	$ 773.15	21,282	$ 16,454,251	$ 35,779,296	45.99%	54.01%
368							$ 69,934,625	$ 129,178,944	**54.14%**	**45.86%**

Unitil Energy
2021 Rate Case Electric Marginal Cost of Service Study
Marginal Cost Summary

A No.	B FERC A/C	C Description	D Units	E Total System	F Domestic	G G2	H G1	I OL
		MARGINAL COST BASED REVENUE REQUIREMENTS REPORT						
1		**Demand Related Carrying Costs**						
2	362	Station Equipment		$ 5,790,215	$ 3,118,096	$ 1,409,227	$ 1,223,114	$ 39,777
3	364-367	Primary System		$ 1,860,253	$ 1,001,768	$ 452,750	$ 392,956	$ 12,779
4	368	Line Transformers		$ 6,604,803	$ 4,646,074	$ 1,323,212	$ 609,128	$ 26,389
5	364-367	Secondary System		$ 3,323,459	$ 2,337,850	$ 665,825	$ 306,506	$ 13,279
6	389-398	General Plant - Demand Related		$ 656,266	$ 361,786	$ 157,536	$ 132,582	$ 4,362
7		Subtotal: Demand Related Carrying Costs		$ 18,234,997	$ 11,465,574	$ 4,008,550	$ 2,664,287	$ 96,587
8		**Demand Related O&M Costs**						
9	920-935	A&G Expense - Demand Related		$ 2,545,690	$ 1,408,958	$ 609,637	$ 510,271	$ 16,824
10		Subtotal: Demand O&M Costs		$ 2,545,690	$ 1,408,958	$ 609,637	$ 510,271	$ 16,824
11		**Total: Demand Related Costs**		**$ 20,780,688**	**$ 12,874,531**	**$ 4,618,187**	**$ 3,174,558**	**$ 113,411**
12		**Customer Related Carrying Costs**						
13	364-367	Primary System		$ 4,003,233	$ 3,392,555	$ 559,035	$ 8,364	$ 43,278
14	368	Line Transformers		$ 9,284,520	$ 7,873,450	$ 1,295,033	$ 15,597	$ 100,441
15	364-367	Secondary System		$ 7,033,214	$ 5,964,299	$ 981,014	$ 11,815	$ 76,086
16	369	Services		$ 7,089,387	$ 5,421,293	$ 1,663,535	$ 4,560	$ -
17	370-371	Meters & Installations		$ 5,795,383	$ 4,289,643	$ 1,430,159	$ 75,581	$ -
18	373	Street Lighting and Signal Systems		$ 514,709	$ -	$ -	$ -	$ 514,709
19	389-398	General Plant - Customer Related		$ 1,936,254	$ 1,512,216	$ 313,300	$ 9,445	$ 101,294
20		Subtotal: Demand Related Carrying Costs		$ 35,656,701	$ 28,453,456	$ 6,242,076	$ 125,361	$ 835,808
21		**Customer Related O&M Costs**						
22	902	Meter Reading Expenses		$ 63,751	$ 47,185	$ 15,732	$ 834	$ -
23	903	Customer Records & Collection Expenses		$ 3,226,861	$ 2,711,528	$ 446,813	$ 6,685	$ 61,835
24	904	Uncollectible Accounts		$ 1,124,573	$ 1,016,425	$ 89,486	$ 14,582	$ 4,079
25	905	Customer Accounts Expenses Supervision		$ 17,026	$ 8,798	$ 8,021	$ 206	$ -
26	908	Customer Assistance Expenses		$ -	$ -	$ -	$ -	$ -
27	909	Informational and Instructional Advertising Exp.		$ 28,775	$ 24,179	$ 3,984	$ 60	$ 551
28	910	Misc. Customer Service & Informational Exp.		$ -	$ -	$ -	$ -	$ -
29	920-935	Customer A&G Costs		$ 7,124,894	$ 5,440,000	$ 1,185,246	$ 156,734	$ 342,914
30		Subtotal: Customer O&M Costs		$ 11,585,879	$ 9,248,116	$ 1,749,283	$ 179,101	$ 409,379
31		**Total: Customer Related Costs**		**$ 47,242,580**	**$ 37,701,572**	**$ 7,991,358**	**$ 304,462**	**$ 1,245,188**
32		**Total LRIC Based Revenue Requirement**		**$ 68,023,268**	**$ 50,576,103**	**$ 12,609,545**	**$ 3,479,020**	**$ 1,358,599**
33		**Actual Revenue Requirement**		**$ 70,048,945**				
34		**True-up Factor**		**1.0298**				
35		**Allocated Actual Revenue Requirement**		**$ 70,048,945**	**$ 52,082,219**	**$ 12,985,047**	**$ 3,582,623**	**$ 1,399,057**
36		**Revenue to Cost Ratio**		0.83	0.61	1.30	2.16	1.30

Unitil Energy
2021 Rate Case Electric Marginal Cost of Service Study
Marginal Cost Summary

A No.	B FERC A/C	C Description	D Units	E Total System	F Domestic	G G2	H G1	I OL
		MARGINAL UNIT COST REPORT						
37		**Demand Related Carrying Costs**						
38	362	Station Equipment		$ 19.21	$ 19.21	$ 19.21	$ 19.21	$ 19.21
39	364-367	Primary System		$ 6.17	$ 6.17	$ 6.17	$ 6.17	$ 6.17
40	368	Line Transformers		$ 21.91	$ 28.62	$ 18.04	$ 9.57	$ 12.74
41	364-367	Secondary System		$ 11.02	$ 14.40	$ 9.08	$ 4.81	$ 6.41
42	389-398	General Plant - Demand Related		$ 2.18	$ 2.23	$ 2.15	$ 2.08	$ 2.11
43		Subtotal: Demand Related Carrying Costs		$ 60.49	$ 70.63	$ 54.64	$ 41.84	$ 46.64
44		**Demand Related O&M Costs**						
45	920-935	A&G Expense - Demand Related		$ 8.44	$ 8.68	$ 8.31	$ 8.01	$ 8.12
46		Subtotal: Demand O&M Costs		$ 8.44	$ 8.68	$ 8.31	$ 8.01	$ 8.12
47		**Total: Demand Related Costs**		**$ 68.94**	**$ 79.31**	**$ 62.95**	**$ 49.85**	**$ 54.76**
48		**$/kW-Month**		**$ 5.74**	**$ 6.61**	**$ 5.25**	**$ 4.15**	**$ 4.56**
49		**Customer Related Carrying Costs**						
50	364-367	Primary System		$ 45.31	$ 49.93	$ 49.93	$ 49.93	$ 4.78
51	368	Line Transformers		$ 105.08	$ 115.89	$ 115.68	$ 93.11	$ 11.10
52	364-367	Secondary System		$ 79.60	$ 87.79	$ 87.63	$ 70.54	$ 8.41
53	369	Services		$ 80.24	$ 79.80	$ 148.59	$ 27.22	$ -
54	370-371	Meters & Installations		$ 65.59	$ 63.14	$ 127.75	$ 451.23	$ -
55	389-398	General Plant - Customer Related		$ 21.92	$ 22.26	$ 27.98	$ 56.39	$ 11.19
56		Subtotal: Customer Related Carrying Costs		$ 397.75	$ 418.80	$ 557.56	$ 748.42	$ 35.48
57		**Customer Related O&M Costs**						
58	902	Meter Reading Expenses		$ 0.72	$ 0.69	$ 1.41	$ 4.98	$ -
59	903	Customer Records & Collection Expenses		$ 36.52	$ 39.91	$ 39.91	$ 39.91	$ 6.83
60	904	Uncollectible Accounts		$ 12.73	$ 14.96	$ 7.99	$ 87.06	$ 0.45
61	905	Customer Accounts Expenses Supervision		$ 0.19	$ 0.13	$ 0.72	$ 1.23	$ -
62	908	Customer Assistance Expenses		$ -	$ -	$ -	$ -	$ -
63	909	Informational and Instructional Advertising Exp.		$ 0.33	$ 0.36	$ 0.36	$ 0.36	$ 0.06
64	910	Misc. Customer Service & Informational Exp.		$ -	$ -	$ -	$ -	$ -
65	920-935	Customer A&G Costs		$ 80.64	$ 80.07	$ 105.87	$ 935.73	$ 37.89
66		Subtotal: Customer O&M Costs		$ 131.13	$ 136.12	$ 156.25	$ 1,069.26	$ 45.24
67		**Total: Customer Related Costs**		**$ 528.88**	**$ 554.92**	**$ 713.81**	**$ 1,817.68**	**$ 80.72**
68		Monthly Costs		$ 44.07	$ 46.24	$ 59.48	$ 151.47	$ 6.73

Unitil Energy
2021 Rate Case Electric Marginal Cost of Service Study
Plant Investment

A No.	B FERC A/C	C Description	D Units		E Total	F Domestic	G G2	H G1	I OL
1		**Billing Determenants**							
2		No. of Customers/Fixtures			88,353	67,940	11,195	168	9,050
3		No. of Customers/Fixtures - Primary			80,169	67,940	11,195	168	867
4		No. of Customers/Fixtures - Secondary			80,116	67,940	11,175	135	867
5		NCP-Demand - Primary	kW		301,451	162,335	73,367	63,678	2,071
6		NCP-Demand - Secondary	kW		504,576	354,939	101,087	46,535	2,016
7		Energy	kWh		1,160,419	515,969	317,057	319,767	7,626
8		Revenue		$	58,056,553	$ 31,580,284	$ 16,916,360	$ 7,736,414	$ 1,823,495
9		**Demand Related Additions**							
10	362	Station Equipment							
11		Investment per unit capacity	$/kW			$159.83	$159.83	$159.83	$159.83
12		Class investment	$	$	48,181,591	$25,946,334	$11,726,474	$10,177,788	$330,995
13		ECCR	%			12.02%	12.02%	12.02%	12.02%
14		Annual Carrying Charge	$	$	5,790,215	$3,118,096	$1,409,227	$1,223,114	$39,777
15		Unit Annual Carrying Costs	$/kW			$19.21	$19.21	$19.21	$19.21
16	364-367	Primary System							
17		Investment per unit capacity	$/kW			$36.45	$36.45	$36.45	$36.45
18		Class investment	$	$	10,988,967	$5,917,684	$2,674,504	$2,321,289	$75,491
19		ECCR				16.93%	16.93%	16.93%	16.93%
20		Annual Carrying Charge	$	$	1,860,253	$1,001,768	$452,750	$392,956	$12,779
21		Unit Annual Carrying Costs	$/kW			$6.17	$6.17	$6.17	$6.17
22	368	Line Transformers							
23		Investment per unit capacity	$/kW			$117.41	$117.41	$117.41	$117.41
24		Class investment	$	$	59,244,319	$41,674,744	$11,869,058	$5,463,810	$236,707
25		ECCR				11.15%	11.15%	11.15%	11.15%
26		Annual Carrying Charge	$	$	6,604,803	$4,646,074	$1,323,212	$609,128	$26,389
27		Unit Annual Carrying Costs	$/kW			$28.62	$18.04	$9.57	$12.74
28	364-367	Secondary System							
29		Investment per unit capacity				$38.91	$38.91	$38.91	$38.91
30		Class investment	$	$	19,632,477	$13,810,244	$3,933,188	$1,810,606	$78,440
31		ECCR				16.93%	16.93%	16.93%	16.93%
32		Annual Carrying Charge	$	$	3,323,459	$2,337,850	$665,825	$306,506	$13,279
33		Unit Annual Carrying Costs	$/kW			$14.40	$9.08	$4.81	$6.41

Unitil Energy
2021 Rate Case Electric Marginal Cost of Service Study
Plant Investment

A No.	B FERC A/C	C Description	D Units	E Total	F Domestic	G G2	H G1	I OL
34		**Customer Related Additions**						
35	364-367	Primary System						
36		Investment per customer	$/Cust		$294.98	$294.98	$294.98	$294.98
37		Class investment	$	$ 23,648,063	$20,040,645	$3,302,353	$49,408	$255,657
38		ECCR			16.93%	16.93%	16.93%	16.93%
39		Annual Carrying Charge	$	$ 4,003,233	$3,392,555	$559,035	$8,364	$43,278
40		Unit Annual Carrying Costs	$/Cust		$49.93	$49.93	$49.93	$4.78
41	368	Line Transformers						
42		Investment per customer	$/Cust		$1,039.51	$1,039.51	$1,039.51	$1,039.51
43		Class investment	$	$ 83,281,070	$70,623,930	$11,616,297	$139,900	$900,943
44		ECCR			11.15%	11.15%	11.15%	11.15%
45		Annual Carrying Charge	$	$ 9,284,520	$7,873,450	$1,295,033	$15,597	$100,441
46		Unit Annual Carrying Costs	$/Cust		$115.89	$115.68	$93.11	$11.10
47	364-367	Secondary System						
48		Investment per customer	$/Cust		$518.58	$518.58	$518.58	$518.58
49		Class investment	$	$ 41,546,898	$35,232,559	$5,795,088	$69,793	$449,458
50		ECCR			16.93%	16.93%	16.93%	16.93%
51		Annual Carrying Charge	$	$ 7,033,214	$5,964,299	$981,014	$11,815	$76,086
52		Unit Annual Carrying Costs	$/Cust		$87.79	$87.63	$70.54	$8.41
53	369	Services						
54		Investment per customer	$/Cust		$708	$ 1,321.35	$300.71	$0.00
55		Class investment	$	$ 62,926,601	$48,120,310	$14,765,820	$40,471	$0
56		ECCR			11.27%	11.27%	11.27%	11.27%
57		Annual Carrying Charge	$	$ 7,089,387	$5,421,293	$1,663,535	$4,560	$0
58		Unit Annual Carrying Costs	$/Cust		$79.80	$148.59	$27.22	$0.00
59	370-371	Meters & Installations						
60		Investment per customer	$/Cust		$357	$ 721.36	$2,548.02	$0.00
61		Class investment	$	$ 32,725,464	$24,222,826	$8,075,844	$426,794	$0
62		ECCR			17.71%	17.71%	17.71%	17.71%
63		Annual Carrying Charge	$	$ 5,795,383	$4,289,643	$1,430,159	$75,581	$0
64		Unit Annual Carrying Costs	$/Cust		$63.14	$127.75	$451.23	$0.00

Unitil Energy
2021 Rate Case Electric Marginal Cost of Service Study
Plant Investment

A No.	B FERC A/C	C Description	D Units		E Total		F Domestic		G G2		H G1		I OL
65		**General Plant**											
66	389-398	Demand Related General Plant											
67		General Plant - ECOSS Demand Allocation		$	7,617,400	$	4,199,315	$	1,828,548	$	1,538,903	$	50,635
68		Less: Accumulated Depreciation		$	(1,917,323)	$	(1,056,981)	$	(460,251)	$	(387,347)	$	(12,745)
69		Net General Plant - Demand Allocation		$	5,700,077	$	3,142,334	$	1,368,297	$	1,151,556	$	37,890
70		Return on Ratebase (Pre Tax)					7.88%		7.88%		7.88%		7.88%
71		Return on Ratebase (Pre Tax)		$	449,166	$	247,616	$	107,822	$	90,743	$	2,986
72		Depreciation Expence		$	207,100	$	114,170	$	49,714	$	41,839	$	1,377
73		Annual Carrying Charge	$	$	656,266.44	$	361,786.08	$	157,536.01	$	132,582.01	$	4,362.35
74		Unit Annual Carrying Costs	$/kW				$2.23		$2.15		$2.08		$2.11
75	389-398	General Plant - Customer Related											
76		General Plant - ECOSS Customer Allocation		$	22,474,444	$	17,552,561	$	3,636,525	$	109,624	$	1,175,733
77		Less: Accumulated Depreciation		$	(5,656,887)	$	(4,418,034)	$	(915,325)	$	(27,593)	$	(295,936)
78		Net General Plant - Demand Allocation		$	16,817,556	$	13,134,527	$	2,721,200	$	82,031	$	879,798
79		Return on Ratebase (Pre Tax)					7.88%		7.88%		7.88%		7.88%
80		Return on Ratebase (Pre Tax)		$	1,325,223	$	1,035,001	$	214,431	$	6,464	$	69,328
81		Depreciation Expence		$	611,031	$	477,216	$	98,869	$	2,980	$	31,966
82		Annual Carrying Charge	$	$	1,936,254	$	1,512,216	$	313,299.72	$	9,444.51	$	101,293.65
83		Unit Annual Carrying Costs	$/Cust				$22.26		$27.98		$56.39		$11.19

Unitil Energy
2021 Rate Case Electric Marginal Cost of Service Study
O&M Expense

A No.	B FERC A/C	C Description	D Units	E Total	F Domestic	G G2	H G1	I OL
1		**Customer Related O&M**						
2	902	Meter Reading Expenses						
3		Meter Reading Expenses			$ 47,185	$ 15,732	$ 834	$ -
4		Expenses per customer			$ 0.69	$ 1.41	$ 4.98	$ -
5	903	Customer Records & Collection Expenses						
6		Customer Records & Collection Expenses			$ 2,711,528	$ 446,813	$ 6,685	$ 61,835
7		Expenses per customer			$ 39.91	$ 39.91	$ 39.91	$ 6.83
8	904	Uncollectible Accounts						
9		Uncollectible Accounts			$ 1,016,425	$ 89,486	$ 14,582	$ 4,079
10		Expenses per customer			$ 14.96	$ 7.99	$ 87.06	$ 0.45
11	905	Customer Accounts Expenses Supervision						
12		Customer Accounts Expenses Supervision			$ 8,798	$ 8,021	$ 206	$ -
13		Expenses per customer			$ 0.13	$ 0.72	$ 1.23	$ -
14	908	Customer Assistance Expenses						
15		Customer Assistance Expenses			$ -	$ -	$ -	$ -
16		Expenses per customer			$ -	$ -	$ -	$ -
17	909	Informational and Instructional Advertising Exp.						
18		Informational and Instructional Advertising Exp.			$ 24,179	$ 3,984	$ 60	$ 551
19		Expenses per customer			$ 0.36	$ 0.36	$ 0.36	$ 0.06
20	910	Misc. Customer Service & Informational Exp.						
21		Misc. Customer Service & Informational Exp.			$ -	$ -	$ -	$ -
22		Expenses per customer			$ -	$ -	$ -	$ -
23	920-935	A&G Expense - Customer Related						
24		A&G Expense - Customer Allocation			$ 5,440,000	$ 1,185,246	$ 156,734	$ 342,914
25		Expenses per customer			$ 80.07	$ 105.87	$ 935.73	$ 37.89
26		**Demand Related O&M**						
27	920-935	A&G Expense - Demand Related						
28		A&G Expense - Demand Allocation			$ 1,408,958	$ 609,637	$ 510,271	$ 16,824
29		Expenses per unit Demand			$ 8.68	$ 8.31	$ 8.01	$ 8.12

Unitil Energy
2021 Rate Case Electric Marginal Cost of Service Study
Lighting Marginal Cost

Unitil Lighting Rate Design - Replacement LED Lights
Estimated Marginal Revenue Requirements

	A	C	D	E
Line No.	Desciption	Count	ECCR on LED Fixtures	Annual Revenue
				C*D
1	STREETLIGHT LED 30W	4,152	$ 48.22	$ 200,230
2	STREETLIGHT LED 50W	175	$ 45.83	$ 8,030
3	STREETLIGHT LED 100W	498	$ 57.30	$ 28,534
4	STREETLIGHT LED 120W	1,074	$ 57.30	$ 61,561
5	STREETLIGHT LED 140W	228	$ 83.49	$ 19,031
6	STREETLIGHT LED 260W	134	$ 107.43	$ 14,373
7	YARDLIGHT LED 35W	440	$ 77.30	$ 34,017
8	YARDLIGHT LED 47W	122	$ 77.30	$ 9,408
9	FLOODLIGHT LED 70W	280	$ 84.15	$ 23,531
10	FLOODLIGHT LED 90W	391	$ 84.15	$ 32,893
11	FLOODLIGHT LED 110W	461	$ 95.17	$ 43,900
12	FLOODLIGHT LED 370W	206	$ 190.71	$ 39,202
13	Special Agreement Customer Installed LED	889	$ -	$ -
14	Total	9,050		$ 514,709

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY

OF

JOHN D. TAYLOR

MANAGING PARTNER
ATRIUM ECONOMICS, LLC

New Hampshire Public Utilities Commission

Docket No. DE 21-030

Table of Contents

<u>Schedules and Attachments</u>

Attachment A	John D. Taylor - Resume
Schedule JDT-1	Rate Design
Schedule JDT-2	LED Lighting Rate Analysis
Schedule JDT-3	Bill Impacts for Current Rates

Direct Testimony of John D. Taylor

I. INTRODUCTION

Q. **Please state your name and business address.**

A. My name is John D. Taylor, and I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner. My business address is 10 Hospital Center Commons, Suite 400 Hilton Head Island SC 29926.

Q. **Please describe your professional background and education.**

A. A copy of my resume is provided as Attachment A. I have been employed as a utility consultant since 2006 providing rate, regulatory, strategic and other consulting services. Prior to joining Atrium I was employed at Black & Veatch Management Consulting and Concentric Energy Advisors. As a utility pricing and policy expert, I am involved in a variety of energy and utility related projects regarding matters pertaining to economics, finance, and public policy. Part of my role within these projects is to conduct various analyses which take into account both accounting and financial considerations and the particular operational configuration of a company's assets. I began my education studying electrical and mechanical engineering and worked for an industrial inspection company, which provided me with hands-on experience with electric utility assets and equipment. I have a B. A. degree in environmental economics from University of North Carolina at Asheville and masters in economics from American University.

Q. **Have you previously testified before the New Hampshire Public Utilities Commission ("the Commission")?**

A. No.

Q. **Please provide a list of state and Canadian jurisdictions in which you have testified.**

A. I have presented expert testimony in state public utility regulatory proceedings in Indiana, Maine, Minnesota, Illinois, Delaware, Pennsylvania, Washington, and West Virginia. In Canada I have provided expert reports before the Ontario Energy Board, the Alberta Energy and Utilities Board, and the British Columbia Utilities Commission. I have also testified before the Federal Energy Regulatory Commission ("FERC") on electric transmission matters. My testimony and expert reports relate to various utility regulatory issues such as cost of service, rate design, affiliate transactions, line extension polices, revenue requirements, and modernization programs such as electric vehicle programs and battery storage projects.

Q. **What is the purpose of your testimony in this proceeding?**

A. Unitil Energy Systems Inc. ("UES" or the "Company") retained Atrium to conduct the allocated class cost of service study ("ACOSS"), the marginal class cost of service study ("MCOSS"), the revenue apportionment and revenue targets by class, the rate design for existing rate classes, Light Emitting Diode ("LED") Lighting rates, and Time-of-Use ("TOU") rates for the domestic class and for electric vehicle ("EV") charging. I am supporting the Company's rate design proposals including new LED Lighting rates, the Domestic TOU rate and TOU rates for EV charging. My colleague Ron Amen is supporting the ACOSS, MCOSS, and revenue apportionment and revenue targets by class in separate testimony.

Q. **Please summarize the content of your testimony and associated schedules.**

A. First, I will discuss various principles of rate design and the rate design proposals for the existing UES rates and for the new LED Lighting rates. I then present the methodology employed to develop four distinct TOU rates for the following new rates (1) Domestic TOU, (2) Domestic TOU for EV Charging, (3) small general service EV TOU Charging (less than 200 kVA), (4) large general service EV TOU Charging (greater than 200 kVA). Lastly, I discuss the TOU bill analyses prepared by Atrium and the proposal for a demand holiday for the two small and large general service EV TOU Rates.

The testimony is supported with the following schedules.

- Schedule JDT-1 – Rate Design
- Schedule JDT-2 – LED Lighting Rate Analysis
- Schedule JDT-3 – Bill Impacts for Current Rates

II. PRINCIPLES OF SOUND RATE DESIGN

Q. **Please identify the principles of rate design utilized in development of the Company's rate design proposals.**

A. Several rate design principles find broad acceptance in the recognized literature on utility ratemaking and regulatory policy. These principles include:

(1) Cost of Service and Cost Causation;

(2) Efficiency;

(3) Value of Service;

(4) Stability/Gradualism;

(5) Non-Discrimination;

(6) Administrative Simplicity; and

(7) Balanced Budget.

Q. **These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by Prof. James Bonbright in his widely-referenced treatise on utility ratemaking, Principles of Public Utility Rates.[1] Can the objectives inherent in these principles compete with each other at times?**

A. Yes, these principles can compete with each other and this tension requires further judgment to strike the right balance between the principles. For example, there is tension between cost of service and value of service principles; efficiency and simplicity; simplicity and non-discrimination; and value of service and non-discrimination. Other potential conflicts arise where utilities face unique circumstances that must be considered as part of the rate design process. Detailed evaluation of rate design recommendations must recognize and effectively address the potential and actual tension between these principles.

Q. **How are these principles translated into the design of rates?**

[1] Bonbright, J. C., Danielson, A. L., & Kamerschen, D. R. (1988). *Principles of Public Utility Rates, Second Edition*. Public Utility Reports, Inc. Page 111-113.

A. The overall rate design process includes the determination of rate structures within rate classes, which entails finding a reasonable balance between the above-described utility rate design principles. Economic, regulatory, historical, and social factors must also be considered in the process. In other words, the rate design process must necessarily include the exercise of judgment, as both quantitative and qualitative information must be evaluated before reaching a final rate design determination.

III. RATE DESIGN PROPOSALS – UPDATES TO CURRENT RATES

Q. **Please summarize the rate design changes UES has proposed in this rate proceeding.**

A. The proposed rate design has capped the customer charge increase at the overall percentage increase for each class. The remaining increase for rates with kWh charges has been included in a flat energy charge. For rates with a demand charge, the remaining increase after the customer charge increase has been added to the demand charge. This emphasis on fixed charges is consistent with the nature of the costs being recovered. UES has proposed the following rate design changes to its current tariff schedules:

(1) Residential – Increase in the Monthly Customer Charge from $16.22 to $21.07, with the remaining proposed increase to be recovered in the Volumetric Charge.

(2) General Service-G1 – Increase in the Monthly Customer Charge from $162.18 to $178.93 for secondary and $86.49 to $95.42 for primary customers, with the remaining proposed increase to be recovered in the Demand Charge.

(3) General Service-G2 Non-Demand - Increase in the Monthly Customer Charge from

$18.38 to $20.28 for non-water heater or space heating and $9.73 to $10.73 for water heating/space heating customers, with the remaining proposed increase to be recovered in the Volumetric Charge.

(4) General Service-G2 Demand – Increase in the Monthly Customer Charge from $29.19 to $32.20, with the remaining proposed increase to be recovered in the Demand Charge.

(5) Lighting – Update the existing fixture rates and introduce new LED fixture rates, as described in more detail below.

Q. **Is UES proposing any new rates?**

A. Yes. The Company is proposing new rates for LED fixtures under its existing Outdoor Lighting rate schedule and LED rate schedule. In addition, UES is proposing four distinct TOU rates:

(1) TOU-D: Domestic TOU rate

(2) TOU-EV-D: Domestic TOU for EV Charging

(3) TOU-EV-G2: small general service EV TOU Charging (less than 200 kVA)

(4) TOU-EV-G1: large general service EV TOU Charging (greater than 200 kVA).

Q. **Overall, what is your conclusion on UES's proposed rate designs as filed in this proceeding?**

A. The Company's proposed rates recognize that while a primary goal of rate design is to seek economic efficiency, consideration should be given to the need for gradualism. The Company is undertaking an increase in rates for all rate classes by increasing all rate components over the current rates. Instead of recovering the full revenue increase entirely through volumetric charges, the Company has proposed a partial increase in the customer charges. This brings the fixed charge closer to the marginal customer cost.

Q. **Please explain the proposed changes to the Company's domestic rate schedule.**

The domestic rate schedule as proposed consists of a $21.07 per month customer charge a result of capping the customer charge increase at the overall percentage increase for the domestic rate class. The remaining increase for rates with kWh charges has been included in a flat energy charge.

Q. **Please explain the rate proposal for the G2 non-demand schedule.**

A. The proposed customer charges for the G2 non-demand billed customers are $20.28 per month and $10.73 per month for water heating/space heating. The remaining proposed revenues are recovered through the volumetric charges.

Q. **Please explain the proposed changes to the Company's G2 and G1 demand rates.**

A. Both the customer charges and demand charges were increased to produce the revenue requirements for each rate schedule. There are no proposed changes to the transformer ownership credit of $0.50 per kW.

Q. **Have you prepared a detailed comparison of the Company's present and proposed rates and resulting revenues by rate class?**

A. Yes. Schedule JDT-1 presents a detailed comparison of present and proposed revenues for each of UES's rate classes.

Q. **Have you prepared bill impact analyses?**

A. Yes, Schedule JDT-3 provides monthly bill impact analyses by class for an appropriate range of monthly usage levels. These analyses demonstrate the combined impact of the rate design changes that are being proposed in this proceeding.

IV. PROPOSAL FOR UPDATED LED LIGHTING RATES

Q. **What are the current Outdoor Lighting rates offered by UES?**

A. The Company currently offers Outdoor Lighting under two rates, Outdoor Lighting Service Schedule OL, which is available to all customers, and Light Emitting Diode Outdoor Lighting Service Schedule LED, which is available to customers who have entered into a Service Agreement and paid the installed costs of the fixtures and brackets.

Q. **Please elaborate on the differences between Schedule OL and Schedule LED.**

A. There are two principal differences between Schedule OL and Schedule LED. First, for customers served under Schedule OL, the Company purchases, installs, owns, and maintains the lighting fixtures, whereas customers served under Schedule LED purchase and pay for the installation of the lighting fixtures, and maintenance is provided by the Company on a charge-per-visit basis. The ownership of the lighting fixtures installed under Schedule LED is transferred to the Company. Service under Schedule LED requires a service agreement. The second principal difference between Schedule OL and Schedule LED is the type of lighting fixtures available. Under Schedule OL, sodium vapor and metal halide luminaires are available, whereas under Schedule LED light emitting diode luminaires are available.

Q. **What has been the market's response to the Schedule LED rate offerings approved in UES's last base rate proceeding?**

A. Of the 9,029 fixtures on UES's distribution grid, 1,736 lighting fixtures were replaced as of December 2020 through the current tariff offering and special contracts with large municipal lighting customers. This represents a conversion of approximately 19% of the lighting fixtures. Current LED technology is sufficiently established to enable the Company to offer LED lighting fixtures under Schedule OL to those customers who may not have an interest or the ability to purchase their own lighting fixtures but would want to choose the type of lighting fixture they prefer. Additionally, there is an operational benefit for the Company to determine what outdoor lighting technology is most appropriate on a going forward basis.

Q. **What new LED outdoor lighting rates are being proposed?**

A. The Company is proposing the following changes to its Outdoor Lighting service: Starting January 1, 2023, it will no longer offer sodium vapor and metal halide luminaires. From that date on, as these legacy fixtures need replacement, they will be replaced with LED fixtures, and there will be no special charges to the customer for this replacement. If, however, a customer requests a conversion of a legacy fixture, or multiple fixtures, to LED service in advance of its actual need, requirement for replacement, or Company planned servicing, the Company may require the customer to pay all or a portion of the costs of the conversions, including labor, material, traffic control, and overheads. Conversions are contingent upon the availability of Company personnel and/or other resources necessary to perform the conversion. Customers wanting to purchase their own LED fixtures will still have that option under Schedule LED if they meet the requirements of Schedule LED.

Q. **What will be the new LED Luminaire charges offered?**

A. The new LED Luminaire charges are specified in Schedule JDT-1. To accommodate the evolution of LED lighting fixtures, the Company proposes to offer luminaire charges encompassing a range of fixtures as opposed to the exact specifications of each individual fixture available on the market today, as provided in the proposed tariff. In addition, lighting fixtures other than that specified in the tariff will be provided only at prices and for a contract term to be mutually agreed upon between the Company and the customer.

Q. **How were the Schedule LED Lighting Rates developed?**

A. Consistent with the current tariff for Schedule LED, any customer wishing to convert to LED will be converted based on the following:

1. Customer will pay the cost of the new LED equipment,
2. Customer will pay the actual cost of installation, and
3. Customer will pay the depreciated book value of the current lighting equipment being removed and cost of removal.

The Company will charge separately for any maintenance cost relating to the new LED fixture on a per-visit basis. In order to determine the fully-allocated rate for the Schedule LED rates, the total cost of service for the Outdoor Lighting class was adjusted down by the amounts related to the net plant associated with the current lighting equipment in service and the depreciation expense and maintenance costs associated with the current lighting equipment. With those costs removed from the embedded cost revenue requirements, unit rates were developed for the LED lighting class which reflects the payments being made for embedded costs by those customers wishing to convert their lighting to LED. These unit rates were then scaled up to the revenue requirement apportioned to the Outdoor Lighting Class to develop the Schedule LED rates as shown on Schedule JDT-3.

Q. **How were the Schedule OL Lighting Rates developed?**

A. The Schedule OL lighting rates were developed using an equivalent fixture procedure. The current tariff lighting fixtures were aligned with an equivalent LED fixture based on lumens output. Then the revenue requirement for the OL lighting rates was calculated using the existing tariff fixtures and rates. This revenue requirement by existing tariff was then aligned with the equivalent LED fixture types. The proposed Schedule OL lighting rates were calculated by dividing the total revenue requirement by LED fixture type by the existing fixtures aligned with the equivalent LED fixture type. This results in the recommended rates for the existing tariff fixtures and the corresponding equivalent LED fixtures being equal for Company paid fixtures. For customer-paid LED fixtures under Schedule OL, the Company paid fixture rates were reduced by an amount equal to the monthly portion of the annual carrying charge of the LED fixtures.

Q. **Does the Company envision that updates will be needed to the rate design during the course of this proceeding?**

A. Yes, the number of conversions to LED lighting is increasing since the test year. The Company anticipates the need to update its rate design to ensure that its revenue requirement will be met using an up-to-date luminaire count.

Q. **What options are available for large municipal lighting customers to utilize lighting control systems?**

A. UES is able to support the development of LED lighting rates for customers with multiple LED lights through their special contract provisions. The special contracts can be developed to contain a provision which would allow the customer to select the output and hours of operation on an annual basis with these updates being reflected in the charges during the next year.

Q. **Have you prepared a schedule supporting calculation of proposed lighting rates?**

A. Yes, proposed rate design calculations are provided in my Schedule JDT-2.

Q. **Has the Company made tariff changes to reflect its proposal as I describe above?**

A. Yes, Schedule OL and Schedule LED have been revised consistent with this proposal and are included in the Company's filing.

V. TIME OF USE RATES

Q. **Please summarize the purpose of this portion of your testimony.**

A. Atrium has developed TOU Rates for UES's Domestic rate class and for EV Charging. This section of my testimony provides a description of the TOU analytics utilized to develop the TOU rates and the resulting bill impacts resulting from the proposed TOU rates.

Q. **Have guiding principles and approaches been provided by the Commission with regard to developing EV TOU Rates?**

A. Yes. There are some guiding principles outlined by the Commission in Order No. 26,394 on August 18, 2020 within Docket IR 20-004. The first excerpt below summarizes Staff's recommendations to the Commission. The second excerpt articulates the Commission's guidance.

> "Staff recommended the Commission issue guidance that any separately-metered residential electric vehicle charging rate should: (1) be based directly on cost causation; (2) incorporate time varying energy supply, transmission, and distribution components; (3) have three periods (e.g., off peak, mid-peak, and peak); (4) be seasonably differentiated (e.g., summer and winter); (5) have an average price differential between off-peak and peak of no less than 3:1; and (6) have a peak period no longer than four hours in duration."[2]

> "The guidelines proposed by the Commission Staff regarding a consistent framework for separately-metered residential electric vehicle charging rate

[2] State of New Hampshire Public Utilities Commission, Order No. 26,394 Docket IR 20-004 dated August 18, 2020 page 15.

designs are appropriate, subject to three clarifications. First, we agree with the City of Lebanon that the five-hour peak duration is more appropriate than the four-hour peak duration. Second, the 3:1 peak to off-peak ratio should represent an average ratio during a given year, not during any one season. Third, we note that these guidelines serve as a useful starting point and are generally consistent with the rate designed and approved for the purposes of Liberty's Battery storage pilot, and later adopted for Liberty's separately-metered EV TOU Rate. Liberty Utilities (Granite State Electric) Corp., Order No. 26,376 at 9. (June 30, 2020)."[3]

Q. **What were the general principles and approaches utilized to develop UES's TOU Rates?**

A. In general, we aimed to follow the Commission's guidance as described above. The goal was to address all issues highlighted through our analyses and this testimony to ensure a full understanding of the options in the context of the principles and approaches outlined by the Commission. A primary principle of our approach is to develop cost causative rate differentials for costs that vary throughout the day as the primary quantitative inputs to the TOU rates. When cost causation is not adhered to we are explicit in the application of non-cost causative principles as qualitative inputs to the TOU rates. In short, the aim is to comply with the Commission's order as detailed in the following excerpt.

[3] State of New Hampshire Public Utilities Commission, Order No. 26,394 Docket IR 20-004 dated August 18, 2020 page 16.

> "We encourage the utilities to consider applying the marginal cost methodology we approved in DE 17-189, as explained in the TOU Technical Statement marked as Exhibit 20 in that docket. Any utility that chooses not to utilize that methodology for its initial proposal should include an explanation in testimony as to why the proposed alternative methodology is appropriate."[4]

Q. **What are the primary rate components that make up the cost of electricity for UES's customers?**

A. There are three main rate components: (1) generation, which is provided through default energy service or through competitive energy suppliers; (2) transmission costs that are separately charged to all customers and adjusted annually; and (3) distribution costs that are set in base rate proceedings. For purposes of developing time-differentiated rates, the costs for default supply were utilized for the generation component. In order to develop a TOU rate, all three components must be considered, and an analysis conducted on how the costs of each component vary across time; either by hour or across blocks of time. As such, a methodology must be developed to ensure the costs assigned to each TOU period are appropriate.

Q. **What method was utilized in determining how the cost of the generation component varies across time?**

A. The method employed by Atrium in our analytics is similar in approach to Liberty's methods as described in the TOU Technical Statement marked as Exhibit 20 in DE 17-

[4] State of New Hampshire Public Utilities Commission, Order No. 26,394 Docket IR 20-004 dated August 18, 2020 page 5.

189 (referred to as the "Liberty Storage Method"). It is also similar to other methods Atrium has employed for TOU rate modeling in other jurisdictions with Independent System Operators and no generation ownership. The general approach is to first differentiate Default Service seasonal energy purchases by time period (i.e. Summer on-peak, Winter off-peak, etc.), using seasonal load profile contributions to each time period as a guide. Second, the marginal cost per hour is calculated by multiplying the average Independent System Operator – New England ("ISO-NE") market clearing Locational Marginal Price ("LMP") for New Hampshire across each hour from multiple years and the class's hourly load over a test year. Third, a time-differentiated marginal rate is calculated by dividing the marginal cost by the Default Service energy purchases for each time period and season. The share for each time period of those time-differentiated marginal rates for each season is then computed to calculate time-of-use ratios. These ratios are then applied to the seasonal Default Service power supply total costs for each time period, resulting in time-differentiated Default Service rates. In addition to time-differentiating the total Default Service power supply costs, the costs associated with line losses and the Renewable Portfolio Standard ("RPS") charge were allocated equally to all time periods such that the rate associated with these costs did not vary across time periods.

Q. **What method was utilized in determining how the cost of the transmission component varies across time?**

A. The method employed by Atrium is similar to the approach utilized within the Liberty Storage Method. The general approach is to time-differentiate UES's annual system transmission cost by season and time period, then divide those costs by time-differentiated system transmission deliveries (kWh). ISO-NE and transmission utility tariffs allocate FERC jurisdictional transmission revenue requirements (Regional Network Service or "RNS" and Local Network Service or "LNS") based on each distribution utility's share of the monthly coincident hour of peak load for the whole system (for RNS) and of their transmission provider's LNS peak. UES's transmission provider (at the LNS connection/wholesale meter point) is Eversource, which uses the system monthly peak for its LNS as well as RNS. The probability of the monthly coincident peak hour occurring during any particular TOU period is assumed to correspond to the historic experience over the most recent ten years split into winter and summer seasons for 60 data points in each season. Those hourly probabilities based on historic experience were then consolidated into the TOU periods. The current volumetric transmission rate (from DE 20-098) was then divided into two components: current transmission charges, allocated as described above, and various reconciliations, mostly prior period under-recovery, which were allocated on a flat volumetric basis to all TOU periods. Current transmission charges were apportioned to the TOU periods based on the assumed probability of monthly coincident peak hours, the cost causation, occurring during each period.

Q. **What analysis was conducted to time-differentiated costs associated with the distribution component?**

A. As discussed earlier in this testimony and previously by UES in past proceedings, the costs associated with the distribution system are fixed in nature. These costs do not vary by time of day and as such have no bearing on the developing a time-of-use rate that is purely cost causative.

Q. **How was the distribution component of costs time-differentiated in the Liberty Storage Method?**

A. The settling parties in DE 17-189 employed a "cost duration method" described as follows:

> "The "cost duration method" was developed . . . to better link the recovery of distribution system costs to the time periods during which system assets are being utilized. In doing so, the resulting rates are intended to accomplish two goals: 1) send a time-differentiated price signal to customers to encourage peak demand reduction, 2) ensure rates for each TOU period reflect the costs of the underlying assets used to meet demand at those times (i.e. cost causation)."[5]

The premise of this method is that there are a small number of peak hours during which system assets necessary to meet demand are used infrequently and thus it is appropriate to assign a significant share of cost for these assets to those peak hours. The approach then assigns another portion of system costs equally to all 8,760 hours of the year. The basic method is akin to a probability-of-dispatch allocation that is sometimes utilized for generating assets and is an attempt to allocate generation capital and fuel across all 8,760

[5] DE 17-189, "Technical Statement Regarding Time-of-Use (TOU) Model" Hearing Exhibit #20 in DE 17-189 (Nov. 29, 2018).

hours and aligning those costs with load duration curves for each rate class across the 8,760 hours.

Q. **Did the TOU modeling conducted by Atrium rely on this method for time differentiating the distribution component?**

A. No. Allocating distribution costs across 8,760 hours based on the peak loads placed on the system during each of those hours does not align with cost causation. Electric utilities invest in distribution infrastructure for two primary purposes (1) to meet the demand requirements of their customers and (2) to extend service to customers and provide dedicated customer related infrastructure like meters and services. Investment relating to extending service to customers (i.e., the customer component of the distribution system discussed by Mr. Amen in separate testimony) in no way varies with peak demand or hour of the day. The level of infrastructure required to meet the demand requirements of customers does vary based on the level of demand but does not vary based on when during the day that demand occurs. If the TOU rates encourage customers to use the system assets during a different time periods there is no reduction in the system assets required to meet the peak demands of those customers; these assets will simply be utilized during a different hour. As such, we did not rely on the Liberty Storage Method to time-differentiate the distribution component.

Q. **Would the shifting of peak demand to off-peak periods reduce some distribution costs over time?**

A. This is possible, but likely for only a small subset of distribution facilities relating to substations where load diversity (load occurring at different hours) can impact the overall investment requirements of a substation. These costs are incurred based on load estimates, where planning and construction can take years with a useful life of over forty years. These costs are functionalized in the Class Cost of Service Study to the sub-transmission function and for the Domestic rate class represent 7.4 percent of the total revenue requirement. Load shifting may have some impact on the level of investment but it would be marginal given these costs only represent a small portion of total system costs, would not impact the utilities costs structure in the next forty years, and would be extremely difficult to estimate.

Q. **What method was utilized to time-differentiate the distribution component of costs?**

A. As further explained below the TOU model utilized is able to separately analyze and develop rates for the generation, transmission, and distribution components. For the "whole house" TOU Domestic Rate the distribution component was not time-differentiated as the costs of providing distribution service does not vary with the hour of the day. To develop the Domestic EV TOU Rate, the distribution component was time-varied in order to produce a TOU rate for all three components with a 3 to 1 on-peak to off-peak ratio as desired by the Commission and expressed in Order 26,394. In short, the allocation of the generation and transmission components across time periods was cost causative but the differentiation of the distribution component for purposes of developing the Domestic TOU EV Rate was to obtain the targeted 3 to 1 on-peak to off-peak ratio as was requested by the Commission.

Q. **Why is UES supporting EV TOU Rates that are not fully cost causative?**

A. As outlined in the testimony of Company witnesses Carroll, Simpson, and Valianti, UES is proposing an EV initiative which contains multiple elements of support for the electrification of the transportation industry. Mass market adoption of EVs will be reliant upon charging networks, and those networks will need to be accessible, convenient, and affordable, particularly at home.

Q. **Please describe the Excel-based model that Atrium utilized to develop the TOU rates.**

A. The Excel-based model allows for the development of time-differentiated rates for each of the three rate components across various time periods. The model provides the ability to define the peak periods across differing time periods and run the analysis for these different time periods. It collates information relating to the LMP clearing price and the transmission hourly peak demands and applies the procedures detailed above. This can be done across various periods of time to develop different options or scenarios. The model also allows for modeling multiple rate classes simultaneously so as time periods are redefined the calculations are updated for all rate classes being reviewed.

Q. **What time period options were analyzed by Atrium when running the TOU rates model?**

A. Atrium utilized the TOU Rates model to review the following four options:

Option 1: Summer (May-Oct); Winter (Nov-Apr)

(a) On-Peak: Non-holiday weekdays, 6am to 8pm

(b) Off-Peak: Non-holiday weekdays, 8pm to 6am. All holidays and weekends.

Option 2: Summer (May-Oct); Winter (Nov-Apr)

(a) On-Peak: Non-holiday weekdays, 6am to 8pm

(b) Off-Peak: Non-holiday weekdays, midnight to 6am. All holidays and weekends.

(c) Mid-Peak: Non-holiday weekdays, 8pm to midnight.

Option 3: Summer (May-Oct); Winter (Nov-Apr)

(a) Super-Peak: Non-holiday weekdays, 3pm to 8pm

(b) On-Peak: Non-holiday weekdays, 6am to 3pm

(c) Off-Peak: Non-holiday weekdays, midnight to 6am. All holidays and weekends.

(d) Mid-Peak: Non-holiday weekdays, 8pm to midnight.

Option 4: Summer (May-Oct); Winter (Nov-Apr)

(a) On-Peak: Non-holiday weekdays, 3pm to 8pm

(b) Off-Peak: Non-holiday weekdays, 8pm to 6am. All holidays and weekends.

(c) Mid-Peak: Non-holiday weekdays, 6am to 3pm

Q. **When developing the domestic TOU Rate, what were the resulting rates for the time periods analyzed under each of the options listed above?**

A. The results can be viewed within Table 1 below for the domestic whole facility TOU rate. As described above only the generation and transmission components were time-differentiated for this rate and the distribution component of the rate is the same during all time periods. Table 2 – Domestic EV TOU Rate provides the results with a time differentiated distribution component. Given the desire to further incentivize the adoption of electric vehicles, and in alignment with Commission guidance discussed above, the Domestic EV TOU Rate (Table 2) is varying the remaining portion of the distribution costs in a manner that results in a total TOU rate with a ratio of 3 to 1 on-peak to off-peak.

Table 1 – Domestic Whole Facility TOU Rate

		Schedule D - Domestic (whole class) TOU Rate							
		Option 1		Option 2		Option 3		Option 4	
	Time Periods	Rate ($/kWh)	Peak:Off-Peak Ratio	Rate ($/kWh)	Peak:Off-Peak Ratio	Rate ($/kWh)	Peak:Off-Peak Ratio	Rate ($/kWh)	Peak:Off-Peak Ratio
Summer: May-Oct	Summer_Super-peak	-	-	-	-	$ 0.2478	2.18	-	-
	Summer_Peak	$ 0.1991	1.76	$ 0.1991	1.76	$ 0.1631	1.44	$ 0.2478	2.19
	Summer_Off-peak	$ 0.1133	1.00	$ 0.1134	1.00	$ 0.1134	1.00	$ 0.1133	1.00
	Summer_Mid-peak	-	-	$ 0.1130	1.00	$ 0.1130	1.00	$ 0.1631	1.44
Winter: Nov-Apr	Winter_Super-peak	-	-	-	-	$ 0.3201	2.35	-	-
	Winter_Peak	$ 0.2210	1.59	$ 0.2210	1.63	$ 0.1507	1.11	$ 0.3201	2.31
	Winter_Off-peak	$ 0.1386	1.00	$ 0.1360	1.00	$ 0.1360	1.00	$ 0.1386	1.00
	Winter_Mid-peak	-	-	$ 0.1482	1.09	$ 0.1482	1.09	$ 0.1507	1.09

Table 2 – Domestic EV TOU Rate

		Schedule D - Domestic EV TOU Rate							
		Option 1		Option 2		Option 3		Option 4	
		Rate ($/kWh)	Peak:Off-Peak Ratio	Rate ($/kWh)	Peak:Off-Peak Ratio	Rate ($/kWh)	Peak:Off-Peak Ratio	Rate ($/kWh)	Peak:Off-Peak Ratio
Summer: May-Oct	Summer_Super-peak	$ -	-	$ -	-	$ 0.2762	3.00	$ -	-
	Summer_Peak	$ 0.2385	3.00	$ 0.2351	3.00	$ 0.1769	1.92	$ 0.2896	3.00
	Summer_Off-peak	$ 0.0795	1.00	$ 0.0783	1.00	$ 0.0921	1.00	$ 0.0965	1.00
	Summer_Mid-peak	$ -	-	$ 0.0979	1.25	$ 0.1117	1.21	$ 0.1663	1.72
Winter: Nov-Apr	Winter_Super-peak	$ -	-	$ -	-	$ 0.3485	3.00	$ -	-
	Winter_Peak	$ 0.2789	3.00	$ 0.2728	3.00	$ 0.1645	1.42	$ 0.3661	3.00
	Winter_Off-peak	$ 0.0930	1.00	$ 0.0909	1.00	$ 0.1162	1.00	$ 0.1220	1.00
	Winter_Mid-peak	$ -	-	$ 0.1232	1.35	$ 0.1484	1.28	$ 0.1541	1.26

As can be seen by comparing Table 1 with Table 2 the on-peak to off-peak ratio for the "whole house" TOU rate varies from 1.59 to 1 through 2.35 to 1 (depending on option and which season); whereas the on-peak to off-peak ratio for the Domestic TOU Rate is set to 3 to 1 for all options.

Q. **Which option is being used for setting the Domestic TOU Rate and the Domestic EV TOU Rate?**

A. The Company is proposing to utilize Option 4. This option provides for three time periods, contains a peak period of five hours, and an off-peak and mid-peak differential that is material. Further, the cost causative components of this TOU rate, the generation and transmission components, result in a 2.23 to 1 ratio for the "whole house" TOU rate. As such, this option aligns most closely with principles of cost causation.

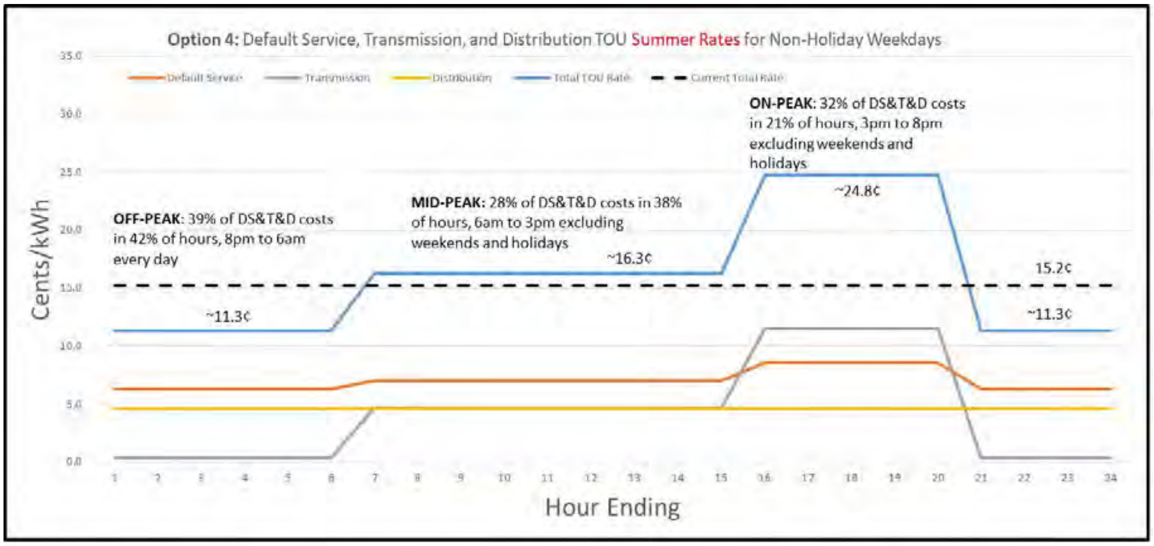
Q. **Can you please summarize the two proposed rates for Domestic TOU and Domestic EV TOU?**

A. The Domestic TOU Rate and the Domestic EV TOU Rates are shown in Table 3 below and contain the three components of the rates. Figures 1 & 2 below show the Domestic TOU Rates and Domestic EV TOU Rates by season. It should be noted that the rates are illustrative as the default service and transmission rates will be at different levels when permanent rates become effective.

Table 3 – Domestic TOU Rate Summary by Component

TOU Period	Default Service Retail TOU Rates ($/kWh)	Transmission TOU Rates ($/kWh)	Flat Distribution TOU Rates ($/kWh)	Total Domestic TOU Rates (w/flat Dist rate) ($/kWh)	Distribution TOU Rates for 3:1 ($/kWh)	Total Domestic EV TOU Rates (w/ Dist TOU Rates) ($/kWh)
Summer_Super-peak	-	-	-	-	-	-
Summer_Peak	0.08594	0.11567	0.04622	0.24783	0.08797	0.28958
Summer_Off-peak	0.06304	0.00408	0.04622	0.11334	0.02941	0.09652
Summer_Mid-peak	0.07003	0.04683	0.04622	0.16308	0.04941	0.16626
Winter_Super-peak	-	-	-	-	-	-
Winter_Peak	0.11167	0.16224	0.04622	0.32013	0.09213	0.36604
Winter_Off-peak	0.08606	0.00629	0.04622	0.13857	0.02965	0.12199
Winter_Mid-peak	0.09655	0.00792	0.04622	0.15069	0.04965	0.15412

Figure 1 – Domestic TOU Rates by Season



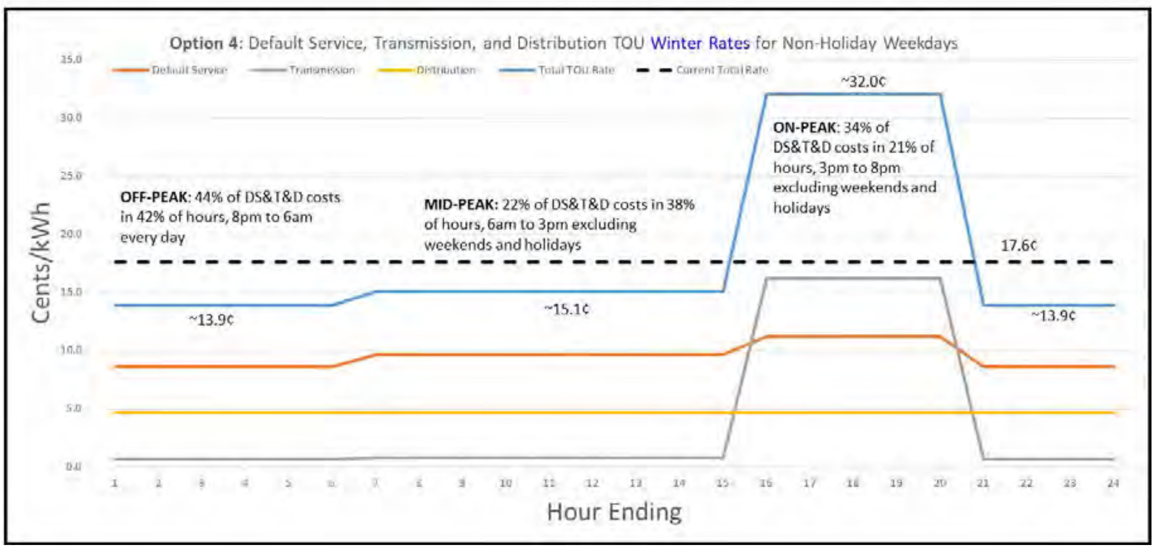
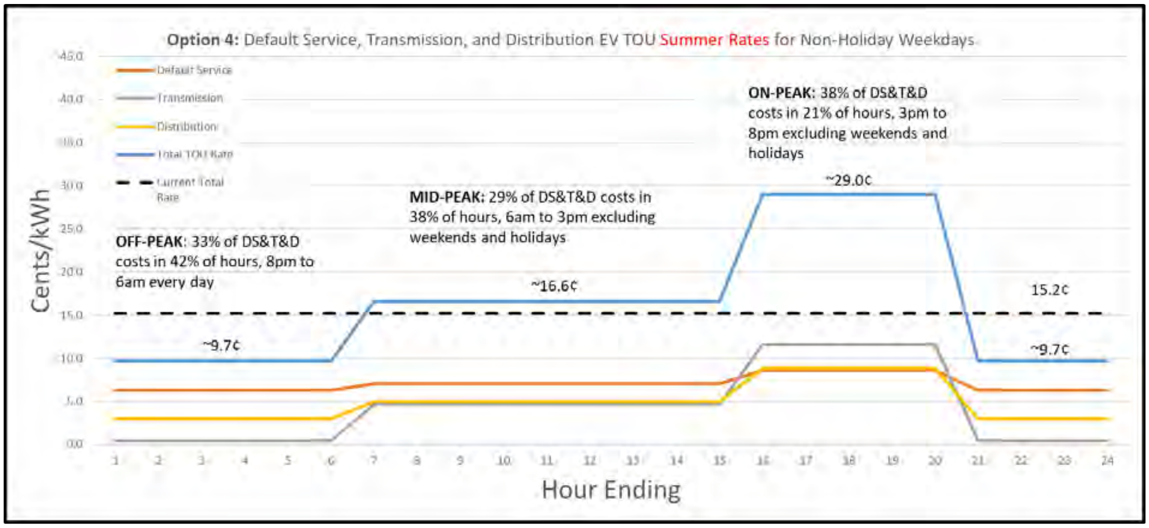
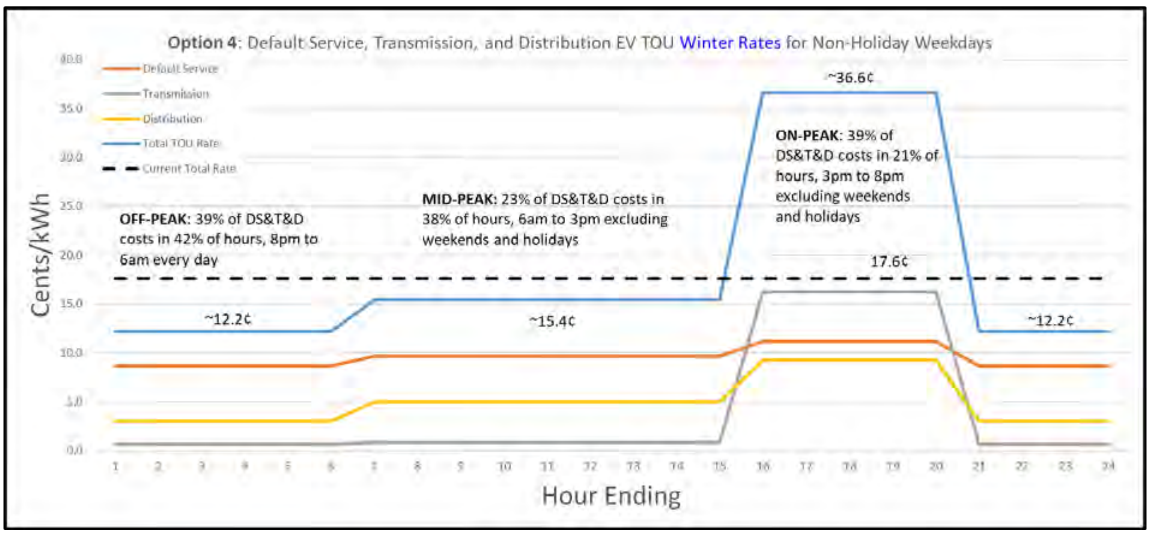


Figure 2 – Domestic EV TOU Rates by Season





Q. **What will the customer charges be for customers on either of these TOU Rates?**

A. The customer charge for the Domestic whole house TOU rate will be the same as the Domestic customer charge. The incremental customer charge for the EV Domestic TOU rate is set at $5.26 which represents the carrying cost associated with a separate meter required to meter the EV charging port.

Q. **What is the process of updating these rates when costs for the generation component and the transmission component are updated?**

A. As UES updates its default service and transmission rates, it will need to update the TOU Rate tariff given the total TOU rates are time varied for the generation component and transmission component. If the proposed TOU rates are approved the ratios set in this proceeding will be used to scale the changes in generation default service costs and transmission costs.

Q. **What analysis was utilized to determine the EV TOU Rates for non-residential charging facilities?**

A. The same method was employed EV TOU Rates for non-residential charging facilities. The same analyses described above for the Domestic TOU Rates were conducted for the generation component and the transmission component within the Excel TOU model, but utilizing data for the G1 and G2 rate classes. The rates developed for EV Charging stations below 200 kVA utilized data from the G2 class whereas the stations with over 200 kVA in demand utilized data from the G1 class. One challenge with modeling the G1 rate class is that the overwhelming majority of G1 customers receive energy from third party suppliers so only the Transmission costs were time-differentiated.

Q. **What are the proposed EV TOU Rates for non-residential charging stations?**

A. The resulting TOU rates for charging stations with <200 kVA are provided below in Table 4 and for charging stations with >200 kVA demand are provided within Table 5.

Table 4 – Proposed TOU Rate for EV Stations with < 200 KVA Demand

TOU Period	Default Service Retail TOU Rates ($/kWh)	Transmission TOU Rates ($/kWh)	Total EV <200 KVA TOU Rates ($/kWh)	Demand Rate ($/kW)
Summer_Super-peak	-	-	-	-
Summer_Peak	0.07378	0.14354	0.21732	11.59
Summer_Off-peak	0.05278	0.00408	0.05686	11.59
Summer_Mid-peak	0.06035	0.03717	0.09752	11.59
Winter_Super-peak	-	-	-	-
Winter_Peak	0.10393	0.17816	0.28209	11.59
Winter_Off-peak	0.07937	0.00647	0.08584	11.59
Winter_Mid-peak	0.09063	0.00699	0.09762	11.59

Table 5 - Proposed TOU Rate for EV Stations with > 200 KVA Demand

TOU Period	Default Service Retail TOU Rates ($/kWh)	Transmission TOU Rates ($/kWh)	Total EV >200 KVA TOU Rates ($/kWh)	Demand Rate ($/KVA)
Summer_Super-peak	-	-	-	-
Summer_Peak	-	0.14117	0.14117	8.37
Summer_Off-peak	-	0.00408	0.00408	8.37
Summer_Mid-peak	-	0.03867	0.03867	8.37
Winter_Super-peak	-	-	-	-
Winter_Peak	-	0.18569	0.18569	8.37
Winter_Off-peak	-	0.00646	0.00646	8.37
Winter_Mid-peak	-	0.00721	0.00721	8.37

In addition to the time-differentiated kWh rates these customers would also be charged a non-time-varying demand rate in alignment with the demand rates for the G1 or G2 rates and the standard customer charge for the G1 or G2 rates. These rates are also illustrative as a new transmission rate would be in effect at the time permanent rates are implemented.

Q. **What unique considerations are taken into account when developing the EV TOU Rates for non-residential charging stations?**

A. There is a higher degree of uncertainty with respect to the charging stations' load profiles, which directly impact their total bills under a TOU rate structure. Further, these charging stations may have limited ability to control or move demand from one time period to another (i.e., their price elasticity can be very low). With regard to load profiles, a workplace or retail host may see demand for charging during the day; whereas a multi-family or condo may have a similar load profile as a residential EV charging port (unless the multi-family or condo parking is in close proximity to retail or workplace in which EV owners can charge during the day as well). Thus, the role of TOU rate differentials in moving demand and consumption to off-peak hours is less predictable across the charging stations and can vary greater from one charging station to another.

Q. **Are demand related charges a significant portion of EV charging facility operating costs?**

A. They can be. Charging facilities, and especially fast charge stations, can result in a high peak demand due to their elevated power level to achieve quicker charging. Demand charges are an increasingly common part of rate structures offered by utilities which charge for the fixed distribution equipment necessary to meet peak demands based on the customer's peak demand (typically based on the maximum amount of power consumed by a customer during a 15-minute period). If a charging station has a low utilization rate (time during a month in which EV owners are charging at the station), the demand portion of their bill can be substantially higher than the actual energy costs. For

EV chargers, demand charges can be initially challenging because EV equipment is likely to be used sporadically to start but still see high power demands, resulting in a final bill heavily tilted towards the demand charges. Such a rate structure may make the economics of EV stations challenging, particularly during the early days of charger installation where EV market penetration is still relatively low. As the number of EVs increase, the likelihood of increasing load factor for these chargers is more likely, resulting in a better balance of energy/demand charges.

Q. **How can these hurdles caused by demand charges impact the electrification of the transportation industry?**

A. These hurdles for early stage charging investment demonstrate the dilemma that tends to follow EVs, where consumers are less likely to buy EVs if chargers are not readily available, but entities are less likely to build those capital-intensive chargers until greater market penetration of EVs increases their ability to recoup their initial cost. The current market for EV charging investment leads some owners to weather early costs from demand charges and low utilization. EV charging availability today will allow for more EV purchases in the future until increasing market penetration and charging station revenues can outweigh the early costs before the end of the lifetime of the charger.

Q. **What tools have been utilized by utilities to address this demand charge dilemma?**

A. Some utilities are utilizing a concept commonly referred to as a demand charge holiday. These are programs where utilities discount demand charges assigned to EV charger networks for a period of time until utilization rates rise and the chargers are economically viable. The actual structure and implementation of a demand charge incentives vary across the country. Options exist for indefinite demand charge holidays to reduce demand charges for EV chargers that ramp up over time to more complicated ways to adjust rate structures for EV infrastructure in a way that accounts for charging utilization. Demand charge holidays have not been the only type of assistance to EV charger networks proposed. Pacific Gas & Electric, for example, required EV operators to predict their monthly power use and then charged customers overage fees if they exceeded that total, similar to a subscription model. New York, on the other hand, offered upfront rebates intended to offset demand charges. There are also proposals to adjust demand charges based on charger utilization rates.

Q. **Can you please provide some examples of electric utilities providing a demand charge holiday for EV charging facilities?**

A. Below I summarize three demand charge holiday programs by (1) Southern California Edison (2) PECO Energy Company in Pennsylvania, and (3) PSE&G in New Jersey. Southern California Edison offered a five-year, 100% demand charge holiday intended to relieve the demand charge burden for EV chargers through 2024, while giving customers time to develop their load management plans. [6] After 2024, the demand charges would gradually ramp up over a five-year period until they reached a new

[6] Nelder, C. (2018). *Rate Design Considerations For EV Charging*. Presented at ACEEE National Convening on Utilities and Electric Vehicles, Atlanta, GA. Retrieved from https://aceee.org/sites/default/files/pdf/conferences/ev/nelder.pdf.

demand charge 40% below the current demand charge rate (which would ideally, at that point, no longer be overly burdensome because utilization rates had increased).[7] PECO Energy Company offers commercial EV chargers a credit against demand charges for three years, with participants able to take advantage of the holiday between 2019 and 2024. The credit equals 50% of the charger.[8] In Rhode Island, National Grid issued credits to offset 100% of demand charges for three years. After this three-year holiday, a distribution demand charge rate would be proposed based on currently available [9] PSE&G in New Jersey offered rebates towards demand charges for EV charger energy consumption, from an available pool of $5 million. The rebates are offered quarterly and will represent 75% of monthly distribution demand charges during the first two years of the program and 50% thereafter (until the $5 million is depleted).[10]

Q. **What is UES proposing with respect to demand charges for new EV charging facilities?**

A. The Company is proposing a demand charge holiday for charging facilities that will provide a 75% discount for the customer's first year of enrollment in the rate, a 50% discount during the second year, and a 25% discount during the third year on the

[7] State of California Public Utilities Commission, Decision 18-05-040 dated May 31, 2018, Application 17-01-020 date of issuance June 6, 2018. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M215/K783/215783846.PDF

[8] Harper, C., McAndrews, G. & Byrnett, D. S. (2019). *Electric Vehicles: Key Trends, Issues, and Considerations for State Regulators*. National Association of Regulatory Utility Commissioners (NARUC). https://pubs.naruc.org/pub/32857459-0005-B8C5-95C6-1920829CABFE

[9] National Grid. Rhode Island Discount Pilot for DCFC Stations. https://www.nationalgridus.com/media/pdfs/bus-ways-to-save/ee7873-ri-discount-pilot-for-dcfc-stations.pdf

[10] State of New Jersey Board of Public Utilities. BPU Docket No. EO18101111. Agenda Date: January 27, 2021. Agenda Item: 8A. https://www.state.nj.us/bpu/pdf/boardorders/2021/20210127/8A%20-%20ORDER%20PSEG%20EV%20Filing.pdf

charging stations demand charges. After the third year, the full demand charge will be applicable.

Q. **Are there other mechanisms that can be employed to lower the demand charges for non-residential charging stations?**

A. Yes. There are a number of technologies available to charging station owners that allow for more control of charging infrastructure to limit peak demand. These technologies utilize set thresholds, algorithms, and machine learning to control the peak demand of the charging stations by controlling individual charging ports. While this technology may not be viable for some charging stations, it does provide the possibility to reduce the overall peak demand of a station for those that choose this additional capital investment and service.

Q. **Have you prepared any bill impacts relating to the EV TOU Rates?**

A. Yes. I have prepared bill impacts for the Domestic EV TOU Rate, the EV TOU Charging Station rate for stations with < 200 kVA and the rate for those stations with >200 kVA. Table 6 below, presents a residential EV rate under the current Domestic tariff and under the EV TOU Rate with no-control of charging periods and presents the same analysis assuming the EV owner controls their charging time (i.e., starts the charge during the off-peak period which can be automatically set for some EVs and charging ports). Further, this analysis was conducted for four typical daily driving amounts: 15 miles (light driver); 30 miles (average driver); 50 miles (heavy driver); and 100 miles (Lyft/Uber driver) with an assumed efficiency of 27 kWh per 100 Miles.

Table 6 – Residential EV TOU Uncontrolled vs. Controlled Charging

Winter - Avg Month	*Uncontrolled Load Profile (charging 3pm-9pm)*				*Controlled/TOU Load Profile (charging 8pm-2am)*			
Driver Profile	**Energy Charges - Current Rate**	**Energy Charges - TOU Rate**	**% Savings**	**$ Savings**	**Energy Charges - Current Rate**	**Energy Charges - TOU Rate**	**% Savings**	**$ Savings**
Light Driver	$ 21.38	$ 42.78	-100%	$ (21.40)	$ 21.38	$ 14.82	31%	$ 6.56
Average Driver	$ 42.76	$ 85.56	-100%	$ (42.80)	$ 42.76	$ 29.64	31%	$ 13.12
Heavy Driver	$ 71.27	$ 142.60	-100%	$ (71.33)	$ 71.27	$ 49.41	31%	$ 21.87
Lyft/Uber	$ 142.55	$ 285.20	-100%	$ (142.65)	$ 142.55	$ 98.81	31%	$ 43.73
Summer Avg Month	*Uncontrolled Load Profile (charging 3pm-9pm)*				*Controlled/TOU Load Profile (charging 8pm-2am)*			
Driver Profile	**Energy Charges - Current Rate**	**Energy Charges - TOU Rate**	**% Savings**	**$ Savings**	**Energy Charges - Current Rate**	**Energy Charges - TOU Rate**	**% Savings**	**$ Savings**
Light Driver	$ 18.46	$ 33.84	-83%	$ (15.38)	$ 18.46	$ 11.73	36%	$ 6.73
Average Driver	$ 36.92	$ 67.69	-83%	$ (30.77)	$ 36.92	$ 23.46	36%	$ 13.46
Heavy Driver	$ 61.53	$ 112.81	-83%	$ (51.28)	$ 61.53	$ 39.09	36%	$ 22.44
Lyft/Uber	$ 123.07	$ 225.62	-83%	$ (102.56)	$ 123.07	$ 78.18	36%	$ 44.88

As can be seen from the above tables, if a residential EV owner charges during the off-peak time, there are demonstrated savings.

Q. **What bill impacts were prepared for the non-residential EV charging stations?**

A. As discussed above, there are technologies available for an EV charging station to reduce their overall peak demand. Table 7 provides two assumed load profiles for a hypothetical work location with ten level 2 charging ports and an average monthly of 18,000 kWh with a monthly peak demand of 164 kW and 124 kW. One load profile assumes no load control and the other assumes load control equipment and program in place.

Table 7 – EV Charging Station with No Load Control and with Load Control

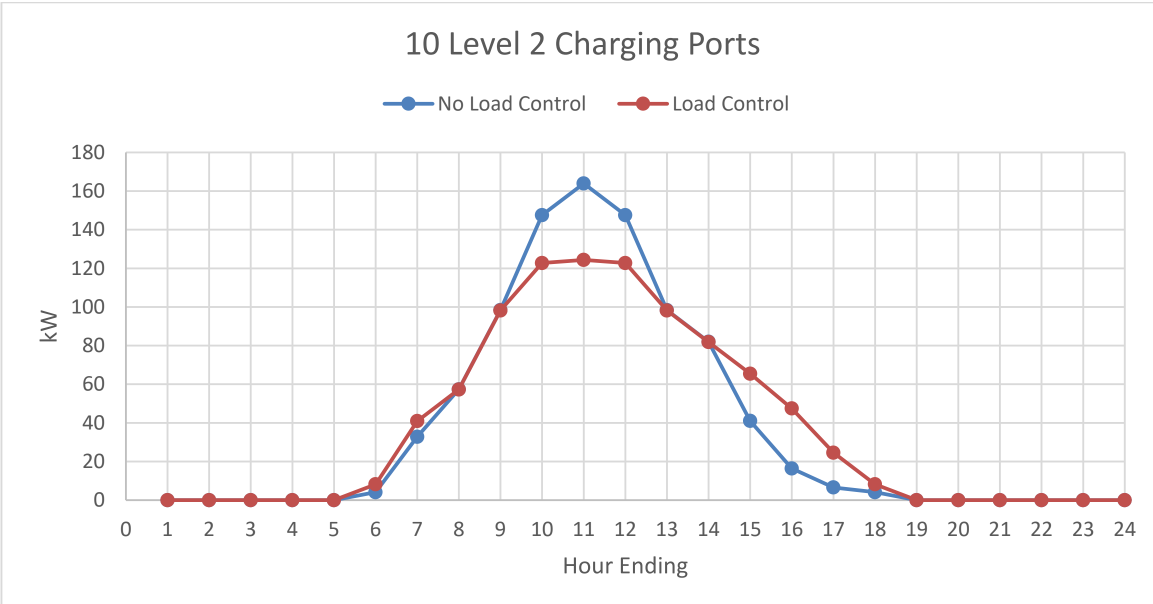


Table 8 below provides an analysis of the resulting total monthly bill for an EV charging station with the two above load profiles; when this customer elects to take service under the EV TOU Rate.

Table 8 – EV Charging Station <200 kVA Customer Avg Month Bill Impacts

Charges	Uncontrolled Load Profile	Controlled Load Profile (24% kW peak reduction)	Savings ($)
Customer Charge ($/month)	$ 32.20	$ 32.20	$ -
Demand Charge Cost ($)	$ 1,900.00	$ 1,441.37	$ 458.63
TOU Energy Charge Cost ($)	$ 1,816.83	$ 1,940.81	$ (123.98)
Total Bill	**$ 3,749.04**	**$ 3,414.39**	**$ 334.65**

The ability to reduce the peak demand by 24 percent can result in a 9 percent savings on the total bill (i.e., $334 divided into $3,749). This same load profile is then used to review the impact of the demand discount which results in an average monthly savings of $1,081 during the first year down to $360 during the last year of the demand holiday program, as presented in Table 9 below.

Table 9 – Demand Discount for Non-Residential EV Charging Station

Controlled Load Profile	Total Bill	w/Demand Discount	Savings ($)
Total Bill w/75% demand cost reduction	$ 3,414.39	$ 2,333.36	$ 1,081.03
Total Bill w/50% demand cost reduction	$ 3,414.39	$ 2,693.71	$ 720.69
Total Bill w/25% demand cost reduction	$ 3,414.39	$ 3,054.05	$ 360.34

Q. **Are similar conclusions reached when reviewing bill impacts for an EV charging station with demand over 200 kVA?**

A. Yes. The same conclusions can be seen in Table 10 below, where a hypothetical DC Fast Charge station was modeled. There are increases to the transmission portion of the customer's bill when moving between the current rate and TOU rates. There are no energy supply costs assumed given that the vast majority of large energy users with greater than 200 kVA utilize third party energy suppliers.

Table 10 – Bill Impact for Large EV Charging Station with >200 kVA

>200 KVA Charging Station	Current Energy Rate	TOU Energy Rate	Savings ($)
Customer Charge - Primary Voltage ($/month)	$ 95.42	$95.42	$ -
Demand Charge Cost ($)	$ 1,823.45	$ 1,823.45	$ -
Transmission Charge Cost ($)	$ 2,256.81	$ 3,566.07	$ (1,309.26)
Total Bill	**$4,175.69**	**$5,484.94**	

	Total Bill	w/Demand Discount	Savings ($)
Total Bill w/75% demand cost reduction	$ 5,484.94	$ 4,117.35	$ 1,367.59
Total Bill w/50% demand cost reduction	$ 5,484.94	*$ 4,573.22*	$ 911.73
Total Bill w/25% demand cost reduction	$ 5,484.94	*$ 5,029.08*	$ 455.86

Q. **What do these bill impacts demonstrate with respect to the TOU Rate proposal and the demand charge holiday proposal?**

A. TOU rates impact customers in different ways depending on their load profile, their peak demand, and the utilization of the station. EV charging stations that are offered to the public or support daytime charging may have limited ability to control or move use from one time period to another (i.e., their price elasticity can be very low). Further, the demand component of their bills can be a large portion of total costs and prohibitive in the development of these stations. The TOU rates proposed by the Company and detailed in this testimony present an opportunity to shift load for those stations with the ability to shift, resulting in societal cost savings and reducing customer bills. In addition, a demand charge holiday can provide an incentive for the development of charging stations supporting the electrification of the transportation industry.

Q. **Does this conclude your direct testimony?**

A. Yes, it does.

John D. Taylor

Managing Partner, Atrium Economics LLC

Mr. Taylor is a utility pricing expert with experience developing cost of service studies for both electric and gas utilities and transmission companies. He has deep experience with developing residential and commercial rates, analyzing midstream transportation and storage capacity resources, and assessing the relationship between price signals and the adoption of distributed generation assets. He has filed testimony as an expert witness on class cost of service studies for both electric and natural gas utilities, return on equity, and on the appropriate use of statistical analysis during audit testing. Mr. Taylor has supported projects involving financial analysis, regulatory support and strategy, market assessment, litigation support, and organizational and operations reviews. He has an expert knowledge of cost allocation principles for utility cost of service studies and for affiliate transaction and service agreements. Mr. Taylor's work often involves providing support for regulatory proceedings by conducting various studies and analyses related to revenue requirements, affiliate transactions, class cost of service, and cash working capital studies. He has also been involved in the sale of generating assets as sell side advisors, supporting due diligence efforts, financial analyses, and regulatory approval processes.

EDUCATION

M.A., Economics, American University

B.A., Environmental Economics, University of North Carolina at Asheville

YEARS EXPERIENCE

15

PROFESSIONAL ASSOCIATIONS

RELEVANT EXPERTISE

Utility Costing and Pricing, Expert Witness Testimony, Transaction Facilitation, Revenue Requirements, Statistics, Valuation, Market Studies, Rate Case Management, New Product and Service Development, Strategic Business Planning, Marketing and Sales

EXPERT WITNESS TESTIMONY PRESENTATION

United States

- Delaware Public Service Commission
- Federal Energy Regulatory Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Maine Public Service Commission
- Massachusetts Department of Public Utilities
- Minnesota Public Utilities Commission
- North Carolina Utilities Commission
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- Washington Utilities and Transportation Commission

Canada

- Alberta Utilities Commission
- British Columbia Utilities Commission
- Ontario Energy Board

REPRESENTATIVE EXPERIENCE

Rate Design and Regulatory Proceedings

Mr. Taylor has worked on dozens of electric and gas rate cases including the development of revenue requirements, class cost of service studies, and projects related to utility rate design issues. Specifically, he has:

- Lead expert and witness for class costs of service studies across North America and worked on dozens of other class cost of service and rate design projects for other lead witnesses.
- Developed WNA mechanism for a gas utility including back casting results and supporting expert witness testimony and exhibits.
- Developed revenue requirement model to comply with a new performance based formula ratemaking process for a Midwest electric utility.
- Supported the developed of time of use rates, demand rates, economic development rates, load retention rates, and line extension policies.
- Analyzed and summarized allocation methodology for a shared services company.
- Assessed the reasonableness of costs through various benchmarking efforts.
- Led the effort to collect and organize plant addition documentation for six Midwest utilities associated with the state commission’s audit of rate base.
- Supported lead-lag analyses and testimonies.
- Analyzed customer usage profiles to support reclassification of rate classes for a gas utility.
- Helped conduct a marginal cost analysis to support rate design testimony.

Litigation Support and Expert Testimony

Mr. Taylor has testified in several cases on class cost of service studies and statistical audit methods. He has also supported numerous other expert testimonies. Specifically, he has:

- Filed testimony as an expert witness on allocated class cost of service studies for both electric and gas utilities.
- Filed testimony as an expert witness on the application of statistical analysis.
- Filed testimony before FERC on the rate of return for an Annual Transmission Revenue Requirement and participated in FERC settlement conferences.
- Part of two person expert witness team that provided an expert report to the British Columbia Utilities Commission on the use of facilities for transportation balancing services for Fortis BC.
- Part of two person expert witness team that provided an expert report on affiliate transactions and capitalized overhead allocations for Hydro One on three separate occasions.
- Sole expert for expert report on affiliate allocations for Alectra utilities, the second largest publicly owned electric utility in North America. This was conducted shortly after the merger of four distinct utilities.

- Sole expert for expert report on the allocation of overhead costs between transmission and distribution businesses for EPCOR.

Transaction Experience

Mr. Taylor has been involved with several generating asset transactions supporting both buy side and sell side analysis and due diligence. His work has included:

- Worked as buy side advisor for a large water utility in the mid-Atlantic region including supporting the review of revenue requirements, rates, and forecasts.
- Helped facilitate and manage processes for a nuclear plant auction by processing Q&A, collecting relevant documentation and managing the virtual data room for auction participants.
- Supported the auction process for steam and chilled water distribution and generation assets in the Midwest.
- Supported the development of a financial model to ascertain the net present value of several competing wholesale power purchase agreements and guided the client with a decision matrix for the qualitative aspects of the offers.
- Provided research on comparable transactions, previous mergers and acquisitions, and potential transaction opportunities for several clients.

Financial Analysis and Market Research

Other financial analysis and market research Mr. Taylor has conducted include:

- Estimated the rate impact and costs associated with moving California energy market to 100% renewable.
- Assessed the consequences of a divestiture on the cost of service model for a New England gas distribution company.
- Developed distributed CNG/LNG market studies for two separate utilities and two separate competitive market participants.
- Modeling alternative mechanisms for the allocation of overhead costs to a nuclear plant.

[THIS PAGE INTENTIONALLY LEFT BLANK]

UNITIL ENERGY SYSTEMS, INC.
12 Months Ended December 31, 2020
Rate Design

Row	Description	Units	Actual Bill Units	Actual Rates & Revenue: Rate	Actual Rates & Revenue: Revenue	Proposed Bill Units	Proposed Rates & Revenue: Rate	Proposed Rates & Revenue: Revenue	Difference Over Actual: Amount	Difference Over Actual: %	Rounding: Amount	Rounding: %
A	B	C	D	E	F	G	H	I	J	K	L	M
1	**Domestic**											
2	Customer Charge		815,280	$16.22	$ 13,223,834	815,280	$21.07	$ 17,179,309	$ 3,955,476	29.9%		
3	Energy Charge	kWh	515,968,592	$ 0.03558	$ 18,358,163	515,968,592	$ 0.04622	$ 23,848,068	$ 5,489,906	29.9%		
4	Subtotal: Domestic				$ 31,581,996			$ 41,027,378				
5	**TOU-D**											
6	Customer Charge						$21.07					
7	Distribution Charge											
8	Summer											
9	Peak						$ 0.04622					
10	Mid-Peak						$ 0.04622					
11	Off-Peak						$ 0.04622					
12	Winter											
13	Peak						$ 0.04622					
14	Mid-Peak						$ 0.04622					
15	Off-Peak						$ 0.04622					
16	Subtotal: Domestic - TOU											
17	Total Schedule D				$ 31,581,996			$ 41,027,378	$ 9,445,382	29.9%	$ (824)	-0.002%
18	**G2 - kWh**											
19	Customer Charge		4,543	$18.38	$ 83,500	4,543	$20.28	$ 92,124	$ 8,624	10.3%		
20	Energy Charge	kWh	438,744	$ 0.00883	$ 3,874	438,744	$ 0.00974	$ 4,273	$ 399	10.3%		
21	Subtotal G2 kWh				$ 87,374			$ 96,398	$ 9,023	10.3%		
22	**G2 QR WH /SH**											
23	Customer Charge		3,089	$9.73	$ 30,056	3,089	$10.73	$ 33,160	$ 3,104	10.3%		
24	Energy Charge	kWh	4,483,579	$ 0.03204	$ 143,654	4,483,579	$ 0.03535	$ 158,495	$ 14,841	10.3%		
25	Subtotal G2 QR WH/SH		7,632		$ 173,710	7,632		$ 191,655	$ 17,945	10.3%		
26	**G2 Demand**											
27	Customer Charge		126,712	$ 29.19	$ 3,698,724	126,712	$ 32.20	$ 4,080,735	$ 382,012	10.3%		
28	Demand Charge	kW	1,234,532	$ 10.51	$ 12,974,933	1,234,532	$ 11.59	$ 14,308,228	$ 1,333,295	10.3%		
29	Transformer Ownership credit	kW	36,843	$ (0.50)	$ (18,421)	36,843	$ (0.50)	$ (18,421)	$ -	0.0%		
30	Energy Charge	kWh	312,134,498	$ -	$ -	312,134,498	$ -	$ -	$ -	0.0%		
31	Subtoal G2 Demand				$ 16,655,236			$ 18,370,542	$ 1,715,306	10.3%		
32	Total G2				$ 16,916,320			$ 18,658,595	$ 1,742,275	10.3%	$ (4,881)	-0.026%

UNITIL ENERGY SYSTEMS, INC.
12 Months Ended December 31, 2020
Rate Design

Row	Description	Units	Actual Bill Units	Actual Rates & Revenue: Rate	Actual Rates & Revenue: Revenue	Proposed Bill Units	Proposed Rates & Revenue: Rate	Proposed Rates & Revenue: Revenue	Difference Over Actual: Amount	Difference Over Actual: %	Rounding: Amount	Rounding: %
A	B	C	D	E	F	G	H	I	J	K	L	M
33	**G1**											
34	Customer Charge											
35	Secondary		1,615	$ 162.18	$ 261,921	1,615	$ 178.93	$ 288,972	$ 27,052	10.3%		
36	Primary		395	$ 86.49	$ 34,164	395	$ 95.42	$ 37,692	$ 3,528	10.3%		
37	Subtotal: Customer Charge				$ 296,084			$ 326,664	$ 30,580	10.3%		
38	Demand Charge	kVA	1,000,283	$ 7.60	$ 7,602,153	1,000,283	$ 8.37	$ 8,372,371	$ 770,218	10.1%		
39	Energy Charge	kWh	319,767,459	$ -	$ -	319,767,459	$ -	$ -	$ -	0.0%		
40	Transformer Ownership credit	kVA	323,647	$ (0.50)	$ (161,824)	323,647	$ (0.50)	$ (161,824)	$ -	0.0%		
41	Total G1				$ 7,736,414			$ 8,537,212	$ 800,798	10.4%	$ 1,766	0.021%
42	**TOU-EV-D**											
43	Customer Charge						$5.26					
44	Distribution Charge											
45	Summer											
46	Peak	kWh					$ 0.08797					
47	Off-Peak	kWh					$ 0.02941					
48	Mid-Peak	kWh					$ 0.04941					
49	Winter											
50	Peak	kWh					$ 0.09213					
51	Off-Peak	kWh					$ 0.02965					
52	Mid-Peak	kWh					$ 0.04965					
53	Total EV TOU - Domestic							$ -	$ -	0.0%		
54	**TOU-EV-G-2**											
55	Customer Charge						$ 32.20					
56	Distribution Charge											
57	Summer											
58	Peak	kWh					$ -					
59	Off-Peak	kWh					$ -					
60	Mid-Peak	kWh					$ -					
61	Winter											
62	Peak	kWh					$ -					
63	Off-Peak	kWh					$ -					
64	Mid-Peak	kWh					$ -					
65	Demand Charge	kW					$ 11.59					
66	Transformer Ownership credit	kW					$ (0.50)					
67	Total EV TOU - G2							$ -	$ -	0.0%		
68	**TOU-EV-G-1**											
69	Customer Charge											

UNITIL ENERGY SYSTEMS, INC.
12 Months Ended December 31, 2020
Rate Design

Row	Description	Units	Actual Bill Units	Actual Rates & Revenue Rate	Actual Rates & Revenue Revenue	Proposed Bill Units	Proposed Rates & Revenue Rate	Proposed Rates & Revenue Revenue	Difference Over Actual Amount	Difference Over Actual %	Rounding Amount	Rounding %
A	B	C	D	E	F	G	H	I	J	K	L	M
70	Secondary						$ 178.93					
71	Primary						$ 95.42					
72	Distribution Charge											
73	Summer											
74	Peak	kWh					$ -					
75	Off-Peak	kWh					$ -					
76	Mid-Peak	kWh					$ -					
77	Winter											
78	Peak	kWh					$ -					
79	Off-Peak	kWh					$ -					
80	Mid-Peak	kWh					$ -					
81	Demand Charge	kVA					$ 8.37					
82	Transformer Ownership credit	kVA					$ (0.50)					
83	Total EV TOU - G1							$ -	$ -	0.0%		
84	**OL**											
85	100W Mercury Vapor Street		13,919	$ 13.28	$ 184,842	13,919	$ 13.73	$ 191,071	$ 6,230	3.4%		
86	175W Mercury Vapor Street		793	$ 15.75	$ 12,493	793	$ 15.73	$ 12,481	$ (12)	-0.1%		
87	250W Mercury Vapor Street		771	$ 17.85	$ 13,754	771	$ 17.25	$ 13,294	$ (459)	-3.3%		
88	400W Mercury Vapor Street		1,298	$ 21.25	$ 27,584	1,298	$ 17.25	$ 22,397	$ (5,187)	-18.8%		
89	1000W Mercury Vapor Street		24	$ 42.19	$ 1,013	24	$ 24.78	$ 595	$ (418)	-41.3%		
90	250W Mercury Vapor Flood		665	$ 19.02	$ 12,652	665	$ 18.25	$ 12,143	$ (509)	-4.0%		
91	400W Mercury Vapor Flood		901	$ 22.75	$ 20,505	901	$ 21.57	$ 19,445	$ (1,060)	-5.2%		
92	1000W Mercury Vapor Flood		144	$ 37.70	$ 5,429	144	$ 25.29	$ 3,641	$ (1,787)	-32.9%		
93	100W Mercury Vapor Power Bracket		3,894	$ 13.41	$ 52,213	3,894	$ 13.44	$ 52,339	$ 126	0.2%		
94	175W Mercury Vapor Power Bracket		557	$ 14.87	$ 8,277	557	$ 14.65	$ 8,154	$ (123)	-1.5%		
95	50W Sodium Vapor Street		35,908	$ 13.52	$ 485,479	35,908	$ 13.73	$ 492,933	$ 7,453	1.5%		
96	100W Sodium Vapor Street		1,309	$ 15.22	$ 19,930	1,309	$ 15.73	$ 20,604	$ 674	3.4%		
97	150W Sodium Vapor Street		3,906	$ 15.28	$ 59,691	3,906	$ 17.25	$ 67,402	$ 7,711	12.9%		
98	250W Sodium Vapor Street		12,893	$ 19.14	$ 246,776	12,893	$ 19.53	$ 251,813	$ 5,037	2.0%		
99	400W Sodium Vapor Street		2,711	$ 24.13	$ 65,421	2,711	$ 24.78	$ 67,195	$ 1,774	2.7%		
100	1000W Sodium Vapor Street		1,606	$ 41.66	$ 66,885	1,606	$ 42.51	$ 68,250	$ 1,365	2.0%		
101	150W Sodium Vapor Flood		2,690	$ 17.61	$ 47,379	2,690	$ 18.25	$ 49,114	$ 1,734	3.7%		
102	250W Sodium Vapor Flood		3,790	$ 20.76	$ 78,671	3,790	$ 21.57	$ 81,756	$ 3,084	3.9%		
103	400W Sodium Vapor Flood		4,857	$ 23.58	$ 114,525	4,857	$ 25.29	$ 122,818	$ 8,293	7.2%		
104	1000W Sodium Vapor Flood		2,467	$ 42.03	$ 103,675	2,467	$ 42.89	$ 105,791	$ 2,116	2.0%		
105	50W Sodium Vapor Power Bracket		1,387	$ 12.51	$ 17,355	1,387	$ 13.44	$ 18,649	$ 1,294	7.5%		
106	100W Sodium Vapor Power Bracket		904	$ 14.04	$ 12,691	904	$ 14.65	$ 13,242	$ 551	4.3%		
107	175W Metal Halide Street		1	$ 19.91	$ 20	1	$ 17.25	$ 17	$ (3)	-13.3%		
108	250W Metal Halide Street		0	$ 21.65	$ -	0	Discontinued					
109	400W Metal Halide Street		0	$ 22.45	$ -	0	Discontinued					
110	175W Metal Halide Flood		0	$ 23.00	$ -	0	Discontinued					
111	250W Metal Halide Flood		0	$ 24.83	$ -	0	Discontinued					
112	400W Metal Halide Flood		0	$ 24.88	$ -	0	Discontinued					
113	175W Metal Halide Power Bracket		0	$ 18.63	$ -	0	Discontinued					
114	250W Metal Halide Power Bracket		0	$ 19.81	$ -	0	Discontinued					
115	400W Metal Halide Power Bracket		0	$ 21.17	$ -	0	Discontinued					
116	1000W Metal Halide Flood (Contracts)		535	$ 32.22	$ 17,222	535	$ 25.29	$ 13,516	$ (3,705)	-21.5%		

UNITIL ENERGY SYSTEMS, INC.
12 Months Ended December 31, 2020
Rate Design

Row	Description	Units	Actual Bill Units	Actual Rates & Revenue Rate	Actual Rates & Revenue Revenue	Proposed Bill Units	Proposed Rates & Revenue Rate	Proposed Rates & Revenue Revenue	Difference Over Actual Amount	Difference Over Actual %	Rounding Amount	Rounding %
A	B	C	D	E	F	G	H	I	J	K	L	M
117	**LED**											
118	42W 3780 K LED Area Light Fixture		0	$ 13.16	$ -	0	Discontinued					
119	57W 5130K LED Area Light Fixture		0	$ 13.21	$ -	0	Discontinued					
120	25W 2500K LED Cobra Head Fixture		0	$ 13.11	$ -	0	Discontinued					
121	88W 8800K LED Cobra Head Fixture		0	$ 13.30	$ -	0	Discontinued					
122	108W 10800K LED Cobra Head Fixture		0	$ 13.36	$ -	0	Discontinued					
123	193W 19300K LED Cobra Head Fixture		0	$ 13.62	$ -	0	Discontinued					
124	123W 11070K LED Flood Light Fixture		0	$ 13.41	$ -	0	Discontinued					
125	227W 20340K LED Flood Light Fixture		0	$ 13.62	$ -	0	Discontinued					
126	365W 32850K LED Flood Light Fixture		0	$ 13.93	$ -	0	Discontinued					
127	**Company Paid LED Fixture**											
128	STREETLIGHT LED 30W						$ 13.73					
129	STREETLIGHT LED 50W						$ 15.73					
130	STREETLIGHT LED 100W						$ 17.25					
131	STREETLIGHT LED 120W						$ 19.53					
132	STREETLIGHT LED 140W						$ 24.78					
133	STREETLIGHT LED 260W						$ 42.51					
134	YARDLIGHT LED 35W						$ 13.44					
135	YARDLIGHT LED 47W						$ 14.65					
136	FLOODLIGHT LED 70W						$ 18.25					
137	FLOODLIGHT LED 90W						$ 21.57					
138	FLOODLIGHT LED 110W						$ 25.29					
139	FLOODLIGHT LED 370W						$ 42.89					
140	**Customer Paid LED Fixture**											
141	STREETLIGHT LED 30W						$ 9.71					
142	STREETLIGHT LED 50W						$ 11.92					
143	STREETLIGHT LED 100W						$ 12.48					
144	STREETLIGHT LED 120W						$ 14.76					
145	STREETLIGHT LED 140W						$ 17.83					
146	STREETLIGHT LED 260W						$ 33.56					
147	YARDLIGHT LED 35W						$ 7.00					
148	YARDLIGHT LED 47W						$ 8.21					
149	FLOODLIGHT LED 70W						$ 11.24					
150	FLOODLIGHT LED 90W						$ 14.56					
151	FLOODLIGHT LED 110W						$ 17.36					
152	FLOODLIGHT LED 370W						$ 27.00					
153	Special Agreement Customer Installed LED		10,671	per contracts	$ 140,376	10,671	per contracts	$ 106,541	$ (33,835)	-24.1%		
154	Pole Charges				$ 8,639			$ 8,639	$ -	0.0%		
155	Total OL				$ 1,823,495			$ 1,823,840	$ 345	0.0%	$ 345	0.019%
156	Total System				$ 58,058,225			$ 70,047,024	$ 11,988,799	20.6%	$ (3,594)	-0.005%

Unitil Lighting Rate Analysis
HID to LED Lighting Fixture Conversion Table with Rates

	A	B	C	D	E	F
Line No.	**Current Outdoor Lighting Tariff Offering**	**Annual Bills**	**Present Rates**	**Fixture Status**	**Equivalent Active Legacy Fixture**	**Replacement LED Fixture**
1	100W Mercury Vapor Street	13,919	$13.28	Discontinued	50W Sodium Vapor Street	STREETLIGHT LED 30W
2	175W Mercury Vapor Street	793	$15.75	Discontinued	100W Sodium Vapor Street	STREETLIGHT LED 50W
3	250W Mercury Vapor Street	771	$17.85	Discontinued	150W Sodium Vapor Street	STREETLIGHT LED 100W
4	400W Mercury Vapor Street	1,298	$21.25	Discontinued	150W Sodium Vapor Street	STREETLIGHT LED 100W
5	1000W Mercury Vapor Street	24	$42.19	Discontinued	400W Sodium Vapor Street	STREETLIGHT LED 140W
6	250W Mercury Vapor Flood	665	$19.02	Discontinued	150W Sodium Vapor Flood	FLOODLIGHT LED 70W
7	400W Mercury Vapor Flood	901	$22.75	Discontinued	250W Sodium Vapor Flood	FLOODLIGHT LED 90W
8	1000W Mercury Vapor Flood	144	$37.70	Discontinued	400W Sodium Vapor Flood	FLOODLIGHT LED 110W
9	100W Mercury Vapor Power Bracket	3,894	$13.41	Discontinued	50W Sodium Vapor Power Bracket	YARDLIGHT LED 35W
10	175W Mercury Vapor Power Bracket	557	$14.87	Discontinued	100W Sodium Vapor Power Bracket	YARDLIGHT LED 47W
11	50W Sodium Vapor Street	35,908	$13.52	Active	50W Sodium Vapor Street	STREETLIGHT LED 30W
12	100W Sodium Vapor Street	1,309	$15.22	Active	100W Sodium Vapor Street	STREETLIGHT LED 50W
13	150W Sodium Vapor Street	3,906	$15.28	Active	150W Sodium Vapor Street	STREETLIGHT LED 100W
14	250W Sodium Vapor Street	12,893	$19.14	Active	250W Sodium Vapor Street	STREETLIGHT LED 120W
15	400W Sodium Vapor Street	2,711	$24.13	Active	400W Sodium Vapor Street	STREETLIGHT LED 140W
16	1000W Sodium Vapor Street	1,606	$41.66	Discontinued	1000W Sodium Vapor Street	STREETLIGHT LED 260W
17	150W Sodium Vapor Flood	2,690	$17.61	Active	150W Sodium Vapor Flood	FLOODLIGHT LED 70W
18	250W Sodium Vapor Flood	3,790	$20.76	Active	250W Sodium Vapor Flood	FLOODLIGHT LED 90W
19	400W Sodium Vapor Flood	4,857	$23.58	Active	400W Sodium Vapor Flood	FLOODLIGHT LED 110W
20	1000W Sodium Vapor Flood	2,467	$42.03	Active	1000W Sodium Vapor Flood	FLOODLIGHT LED 370W
21	50W Sodium Vapor Power Bracket	1,387	$12.51	Active	50W Sodium Vapor Power Bracket	YARDLIGHT LED 35W
22	100W Sodium Vapor Power Bracket	904	$14.04	Active	100W Sodium Vapor Power Bracket	YARDLIGHT LED 47W
23	175W Metal Halide Street	1	$19.91	Discontinued	150W Sodium Vapor Street	STREETLIGHT LED 100W

Unitil Lighting Rate Analysis
HID to LED Lighting Fixture Conversion Table with Rates

	A	B	G	H	I	J	K
Line No.	**Current Outdoor Lighting Tariff Offering**	**Annual Bills**	**LED Fixture Cost (per month)**	**Current Revenue**	**Proposed Revenue**	**Proposed Rate Company Installed**	**Proposed Rate Customer Installed**
1	100W Mercury Vapor Street	13,919	$8.02	$184,841.76	$191,071.30	$13.73	$9.71
2	175W Mercury Vapor Street	793	$7.97	$12,493.30	$12,481.16	$15.73	$11.92
3	250W Mercury Vapor Street	771	$9.30	$13,753.53	$13,294.33	$17.25	$12.48
4	400W Mercury Vapor Street	1,298	$9.30	$27,583.55	$22,396.58	$17.25	$12.48
5	1000W Mercury Vapor Street	24	$11.78	$1,012.56	$594.82	$24.78	$17.83
6	250W Mercury Vapor Flood	665	$11.31	$12,651.82	$12,142.73	$18.25	$11.24
7	400W Mercury Vapor Flood	901	$11.46	$20,505.06	$19,445.04	$21.57	$14.56
8	1000W Mercury Vapor Flood	144	$12.53	$5,428.80	$3,641.39	$25.29	$17.36
9	100W Mercury Vapor Power Bracket	3,894	$10.48	$52,212.69	$52,339.12	$13.44	$7.00
10	175W Mercury Vapor Power Bracket	557	$10.57	$8,276.65	$8,153.84	$14.65	$8.21
11	50W Sodium Vapor Street	35,908	$8.02	$485,479.46	$492,932.68	$13.73	$9.71
12	100W Sodium Vapor Street	1,309	$7.97	$19,929.85	$20,603.82	$15.73	$11.92
13	150W Sodium Vapor Street	3,906	$9.30	$59,690.64	$67,402.08	$17.25	$12.48
14	250W Sodium Vapor Street	12,893	$9.45	$246,776.06	$251,813.31	$19.53	$14.76
15	400W Sodium Vapor Street	2,711	$11.78	$65,421.44	$67,195.25	$24.78	$17.83
16	1000W Sodium Vapor Street	1,606	$14.67	$66,885.13	$68,250.41	$42.51	$33.56
17	150W Sodium Vapor Flood	2,690	$11.31	$47,379.38	$49,113.84	$18.25	$11.24
18	250W Sodium Vapor Flood	3,790	$11.46	$78,671.40	$81,755.83	$21.57	$14.56
19	400W Sodium Vapor Flood	4,857	$12.53	$114,524.98	$122,817.88	$25.29	$17.36
20	1000W Sodium Vapor Flood	2,467	$22.44	$103,674.51	$105,790.74	$42.89	$27.00
21	50W Sodium Vapor Power Bracket	1,387	$10.48	$17,354.97	$18,648.58	$13.44	$7.00
22	100W Sodium Vapor Power Bracket	904	$10.57	$12,690.85	$13,241.65	$14.65	$8.21
23	175W Metal Halide Street	1	$9.30	$19.91	$17.25	$17.25	$12.48

Unitil Lighting Rate Analysis
HID to LED Lighting Fixture Conversion Table with Rates

	A	B	C	D	E	F
Line No.	Current Outdoor Lighting Tariff Offering	Annual Bills	Present Rates	Fixture Status	Equivalent Active Legacy Fixture	Replacement LED Fixture
24	250W Metal Halide Street	0	$21.65	Discontinued	N/A	
25	400W Metal Halide Street	0	$22.45	Discontinued	N/A	
26	175W Metal Halide Flood	0	$23.00	Discontinued	N/A	
27	250W Metal Halide Flood	0	$24.83	Discontinued	N/A	
28	400W Metal Halide Flood	0	$24.88	Discontinued	N/A	
29	175W Metal Halide Power Bracket	0	$18.63	Discontinued	N/A	
30	250W Metal Halide Power Bracket	0	$19.81	Discontinued	N/A	
31	400W Metal Halide Power Bracket	0	$21.17	Discontinued	N/A	
32	1000W Metal Halide Flood (Contracts)	535	$32.22	Active	400W Sodium Vapor Flood	FLOODLIGHT LED 110W
33	42W 3780 K LED Area Light Fixture	0	$13.16	Discontinued	N/A	
34	57W 5130K LED Area Light Fixture	0	$13.21	Discontinued	N/A	
35	25W 2500K LED Cobra Head Fixture	0	$13.11	Discontinued	N/A	
36	88W 8800K LED Cobra Head Fixture	0	$13.30	Discontinued	N/A	
37	108W 10800K LED Cobra Head Fixture	0	$13.36	Discontinued	N/A	
38	193W 19300K LED Cobra Head Fixture	0	$13.62	Discontinued	N/A	
39	123W 11070K LED Flood Light Fixture	0	$13.41	Discontinued	N/A	
40	227W 20340K LED Flood Light Fixture	0	$13.62	Discontinued	N/A	
41	365W 32850K LED Flood Light Fixture	0	$13.93	Discontinued	N/A	
42	Special Agreement Customer Installed LED	10,671	$13.19	Active		
43		108,600				

Unitil Lighting Rate Analysis
HID to LED Lighting Fixture Conversion Table with Rates

	A	B	G	H	I	J	K
Line No.	**Current Outdoor Lighting Tariff Offering**	**Annual Bills**	**LED Fixture Cost (per month)**	**Current Revenue**	**Proposed Revenue**	**Proposed Rate Company Installed**	**Proposed Rate Customer Installed**
24	250W Metal Halide Street	0		$0.00	$0.00		
25	400W Metal Halide Street	0		$0.00	$0.00		
26	175W Metal Halide Flood	0		$0.00	$0.00		
27	250W Metal Halide Flood	0		$0.00	$0.00		
28	400W Metal Halide Flood	0		$0.00	$0.00		
29	175W Metal Halide Power Bracket	0		$0.00	$0.00		
30	250W Metal Halide Power Bracket	0		$0.00	$0.00		
31	400W Metal Halide Power Bracket	0		$0.00	$0.00		
32	1000W Metal Halide Flood (Contracts)	535	$12.53	$17,221.59	$13,516.15	$25.29	$17.36
33	42W 3780 K LED Area Light Fixture	0		$0.00	$0.00		
34	57W 5130K LED Area Light Fixture	0		$0.00	$0.00		
35	25W 2500K LED Cobra Head Fixture	0		$0.00	$0.00		
36	88W 8800K LED Cobra Head Fixture	0		$0.00	$0.00		
37	108W 10800K LED Cobra Head Fixture	0		$0.00	$0.00		
38	193W 19300K LED Cobra Head Fixture	0		$0.00	$0.00		
39	123W 11070K LED Flood Light Fixture	0		$0.00	$0.00		
40	227W 20340K LED Flood Light Fixture	0		$0.00	$0.00		
41	365W 32850K LED Flood Light Fixture	0		$0.00	$0.00		
42	Special Agreement Customer Installed LED	10,671		$140,720.82	$106,540.92		
43		108,600		$1,815,200.71	$1,815,200.71		

Unitil Lighting Rate Analysis
HID to LED Lighting Fixture Conversion Table with Rates

	A	B	G	H	I	J	K	
Line No.	**Current Outdoor Lighting Tariff Offering**	**Annual Bills**	**LED Fixture Cost (per month)**	**Current Revenue**	**Proposed Revenue**	**Proposed Rate Company Installed**	**Proposed Rate Customer Installed**	
44								
45								
46	**Current Outdoor Lighting Tariff Offering**	**Annual Bills**	**LED Fixture Cost (per month)**	**Current Revenue**	**Proposed Revenue**	**Proposed Rate Company Installed**	**Proposed Rate Customer Installed**	**Discount on Customer Installed**
47	STREETLIGHT LED 30W	49,827	$8.02	$ 670,321	$ 684,004	$ 13.73	$ 9.71	$ 4.02
48	STREETLIGHT LED 50W	2,103	$7.97	$ 32,423	$ 33,085	$ 15.73	$ 11.92	$ 3.82
49	STREETLIGHT LED 100W	5,976	$9.30	$ 101,048	$ 103,110	$ 17.25	$ 12.48	$ 4.77
50	STREETLIGHT LED 120W	12,893	$9.45	$ 246,776	$ 251,813	$ 19.53	$ 14.76	$ 4.77
51	STREETLIGHT LED 140W	2,735	$11.78	$ 66,434	$ 67,790	$ 24.78	$ 17.83	$ 6.96
52	STREETLIGHT LED 260W	1,606	$14.67	$ 66,885	$ 68,250	$ 42.51	$ 33.56	$ 8.95
53	YARDLIGHT LED 35W	5,281	$10.48	$ 69,568	$ 70,988	$ 13.44	$ 7.00	$ 6.44
54	YARDLIGHT LED 47W	1,461	$10.57	$ 20,968	$ 21,395	$ 14.65	$ 8.21	$ 6.44
55	FLOODLIGHT LED 70W	3,356	$11.31	$ 60,031	$ 61,257	$ 18.25	$ 11.24	$ 7.01
56	FLOODLIGHT LED 90W	4,691	$11.46	$ 99,176	$ 101,201	$ 21.57	$ 14.56	$ 7.01
57	FLOODLIGHT LED 110W	5,535	$12.53	$ 137,175	$ 139,975	$ 25.29	$ 17.36	$ 7.93
58	FLOODLIGHT LED 370W	2,467	$22.44	$ 103,675	$ 105,791	$ 42.89	$ 27.00	$ 15.89
59	Special Agreement Customer Installed LED	10,671		$ 140,721	$ 106,541		$ -	$ -
60		108,600		$ 1,815,201	$ 1,815,201			
61								

Unitil Lighting Rate Analysis
Cost Based Analysis of HID and LED Lighting Fixtures

	A	B	C	D	E	F	G
Line No.	**Desciption**	**Watts**	**Installed Cost $2021**	**Demand Costs**	**Customer Costs**	**Annual Distribution Revenue Requirement**	**Annual Fixture Carrying Charge**
				B x Demand Cost/1000	Customer Component*12	D+E	C x ECCR
1	Current HID Lighting Stock						
2	FLOODLIGHT 150W HPS	150	$398.08	$13.47	$45.31	$58.78	$70.45
3	FLOODLIGHT 250W HPS	250	$434.99	$22.45	$45.31	$67.76	$76.98
4	FLOODLIGHT 400W HPS	400	$459.15	$35.91	$45.31	$81.22	$81.26
5	FLOODLIGHT 1000W HPS	1000	$459.66	$89.78	$45.31	$135.09	$81.35
6	FLOODLIGHT 1000WMV/MH	1000	$659.61	$89.78	$45.31	$135.09	$116.73
7	LUMINAIRE HPS 50	50	$284.92	$4.49	$45.31	$49.80	$50.42
8	LUMIN HPS 50W YARD LT	50	$401.89	$4.49	$45.31	$49.80	$71.12
9	LUMINAIRE HPS 100	100	$278.95	$8.98	$45.31	$54.29	$49.37
10	LUMIN HPS 100 YARD LT	100	$401.89	$8.98	$45.31	$54.29	$71.12
11	LUMINAIRE HPS 150	150	$312.63	$13.47	$45.31	$58.78	$55.33
12	LUMINAIRE HPS 250	250	$359.19	$22.45	$45.31	$67.76	$63.57
13	LUMINAIRE HPS 250 COF	250	$316.50	$22.45	$45.31	$67.76	$56.01
14	LUMINAIRE HPS 400	400	$425.04	$35.91	$45.31	$81.22	$75.22
15	LUMINAIRE HPS 400 COF	400	$354.58	$35.91	$45.31	$81.22	$62.75
16							

Unitil Lighting Rate Analysis
Cost Based Analysis of HID and LED Lighting Fixtures

H	I	J	K
Total Annual Cost for Company Installed Light Fixtures	**Monthly Cost for Company Installed Light Fixtures**	**Monthly Cost for Customer Installed Light Fixtures**	**Installation Discount**
F+G	H/12	F/12	I-J
$129.23	$10.77		
$144.74	$12.06		
$162.48	$13.54		
$216.44	$18.04		
$251.83	$20.99		
$100.22	$8.35		
$120.92	$10.08		
$103.66	$8.64		
$125.41	$10.45		
$114.11	$9.51		
$131.32	$10.94		
$123.77	$10.31		
$156.44	$13.04		
$143.98	$12.00		

Unitil Lighting Rate Analysis
Cost Based Analysis of HID and LED Lighting Fixtures

	A	B	C	D	E	F	G
Line No.	**Desciption**	**Watts**	**Installed Cost $2021**	**Demand Costs**	**Customer Costs**	**Annual Distribution Revenue Requirement**	**Annual Fixture Carrying Charge**
				B x Demand Cost/1000	Customer Component*12	D+E	C x ECCR
37	Replacement LED Lighting Stock						
38	STREETLIGHT LED 30W	30	$327.51	$2.69	$45.31	$48.00	$48.22
39	STREETLIGHT LED 50W	50	$311.24	$4.49	$45.31	$49.80	$45.83
40	STREETLIGHT LED 100W	100	$389.14	$8.98	$45.31	$54.29	$57.30
41	STREETLIGHT LED 120W	120	$389.14	$10.77	$45.31	$56.08	$57.30
42	STREETLIGHT LED 140W	140	$567.05	$12.57	$45.31	$57.88	$83.49
43	STREETLIGHT LED 260W	260	$729.62	$23.34	$45.31	$68.65	$107.43
44	YARDLIGHT LED 35W	35	$525.00	$3.14	$45.31	$48.45	$77.30
45	YARDLIGHT LED 47W	47	$525.00	$4.22	$45.31	$49.53	$77.30
46	FLOODLIGHT LED 70W	70	$571.50	$6.28	$45.31	$51.60	$84.15
47	FLOODLIGHT LED 90W	90	$571.50	$8.08	$45.31	$53.39	$84.15
48	FLOODLIGHT LED 110W	110	$646.37	$9.88	$45.31	$55.19	$95.17
49	FLOODLIGHT LED 370W	370	$1,295.26	$33.22	$45.31	$78.53	$190.71
50							
51							

Line No.	Description		Amount	Source
53	Demand Component Cost ($/kW)	$	89.78	ACOSS
54	Customer-Related Revenue Requirement	$	1,220,529	ACOSS
55	Revenue Requirement Associated with Fixtures	$	810,466	ACOSS
56	Total Customer Component w/o Fixtures	$	410,063	
57	Number of Fixtures		108,600	
58	Customer Component Cost ($/fixture)	$	3.78	
59	Proposed Revenue to Cost Ratio of Existing Lighting		1.32	Revenue Apportionment

Unitil Lighting Rate Analysis
Cost Based Analysis of HID and LED Lighting Fixtures

H	I	J	K
Total Annual Cost for Company Installed Light Fixtures	**Monthly Cost for Company Installed Light Fixtures**	**Monthly Cost for Customer Installed Light Fixtures**	**Installation Discount**
F+G	H/12	F/12	I-J
$96.23	$8.02	$4.00	$4.02
$95.63	$7.97	$4.15	$ 3.82
$111.59	$9.30	$4.52	$ 4.77
$113.38	$9.45	$4.67	$ 4.77
$141.37	$11.78	$4.82	$ 6.96
$176.08	$14.67	$5.72	$ 8.95
$125.75	$10.48	$4.04	$ 6.44
$126.83	$10.57	$4.13	$ 6.44
$135.74	$11.31	$4.30	$ 7.01
$137.54	$11.46	$4.45	$ 7.01
$150.36	$12.53	$4.60	$ 7.93
$269.24	$22.44	$6.54	$15.89

[THIS PAGE INTENTIONALLY LEFT BLANK]

Unitil Energy Systems, Inc.
Typical Bill Impacts as a Result of Proposed Rates
Impact on D Rate Customers

Range Monthly kWh	Percentage Bills	Average kWh	Total Bill Using Rates Effective 12/1/2020	Total Bill Using Rates Proposed	Total Difference	% Total Difference
0-100	7.6%	38	$22.71	$27.87	$5.17	22.7%
101-200	8.2%	154	$42.79	$48.93	$6.14	14.3%
201-300	10.4%	252	$59.78	$66.74	$6.96	11.6%
301-400	11.2%	351	$76.89	$84.67	$7.78	10.1%
401-500	10.8%	450	$94.06	$102.68	$8.62	9.2%
501-750	21.6%	617	$122.87	$132.88	$10.01	8.1%
750-1,000	13.0%	864	$165.67	$177.74	$12.08	7.3%
1,000-1,500	11.2%	1,201	$223.98	$238.87	$14.90	6.7%
1,501-2,000	3.6%	1,707	$311.56	$330.69	$19.13	6.1%
2,001-3,500	2.0%	2,447	$439.52	$464.83	$25.32	5.8%
3,501-5,000	0.2%	4,021	$711.82	$750.30	$38.48	5.4%
5,000+	0.0%	6,632	$1,163.39	$1,223.70	$60.31	5.2%
600 kWh bill		600	$120.00	$129.87	$9.87	8.2%

Unitil Energy Systems, Inc.
Rates - Effective 12/1/2020:

Customer Charge	**$16.22**
	All kWh
Distribution Charge	$0.03558
External Delivery Charge	$0.03613
Stranded Cost Charge	($0.00025)
System Benefits Charge	$0.00752
Storm Recovery Adjustment Factor	$0.00084
Fixed Default Service Charge	$0.09315
TOTAL	**$0.17297**

Unitil Energy Systems, Inc.
Rates - Proposed:

Customer Charge	**$21.07**
	All kWh
Distribution Charge	$0.04622
External Delivery Charge [1]	$0.03478
Stranded Cost Charge	($0.00025)
System Benefits Charge [1]	$0.00659
Storm Recovery Adjustment Factor	$0.00084
Fixed Default Service Charge	$0.09315
TOTAL	**$0.18133**

Note [1]: Present rates adjusted to reflect costs moving into base distribution charge rates

Unitil Energy Systems, Inc.
Typical Bill Impacts as a Result of Proposed Rates
Impact on G2 Rate Customers

Average Load Factor	kW Range	Percentage Bills	Average Monthly kW	Average Monthly kWh	Total Bill Using Rates Effective 12/1/2020	Total Bill Using Rates Proposed	Total Difference	% Total Difference
17%	0-1.0	26.9%	1.0	125	$55.95	$59.76	$3.80	6.8%
28%	1.1-2	10.6%	1.5	308	$85.30	$89.22	$3.92	4.6%
24%	2.1-3	7.4%	2.5	438	$113.14	$117.89	$4.74	4.2%
24%	3.1-4	6.5%	3.5	625	$148.39	$153.80	$5.41	3.6%
25%	4.1-5	5.9%	4.5	821	$184.69	$190.74	$6.05	3.3%
24%	5.1-6	5.4%	5.5	965	$213.92	$220.71	$6.80	3.2%
24%	6.1-7	4.2%	6.5	1,141	$247.50	$254.97	$7.47	3.0%
25%	7.1-8	3.6%	7.5	1,351	$285.67	$293.75	$8.09	2.8%
26%	8.1-9	3.0%	8.5	1,622	$331.70	$340.24	$8.53	2.6%
27%	9.1-10	2.6%	9.5	1,872	$375.07	$384.13	$9.05	2.4%
28%	10.1-12	4.2%	11.0	2,219	$435.87	$445.70	$9.83	2.3%
29%	12.1-14	2.9%	13.0	2,800	$533.28	$543.96	$10.68	2.0%
31%	14.1-16	2.4%	15.0	3,390	$631.83	$643.34	$11.51	1.8%
33%	16.1-18	1.8%	17.0	4,048	$739.35	$751.53	$12.17	1.6%
33%	18.1-20	1.4%	19.0	4,598	$832.52	$845.61	$13.08	1.6%
34%	20.1-22.5	1.4%	21.3	5,309	$949.55	$963.44	$13.89	1.5%
35%	22.6-25	1.2%	23.7	6,017	$1,068.24	$1,083.17	$14.93	1.4%
37%	25.1-30	1.6%	27.4	7,335	$1,280.33	$1,296.26	$15.93	1.2%
40%	30.1-35	1.1%	32.5	9,376	$1,601.39	$1,618.12	$16.73	1.0%
40%	35.1-40	0.9%	37.5	11,085	$1,878.99	$1,897.30	$18.30	1.0%
40%	40.1-45	0.7%	42.5	12,531	$2,120.89	$2,141.25	$20.35	1.0%
43%	45.1-50	0.6%	47.5	14,838	$2,476.64	$2,497.16	$20.52	0.8%
42%	50.1-60	0.9%	54.8	16,705	$2,798.24	$2,822.37	$24.14	0.9%
43%	60.1-70	0.7%	64.8	20,391	$3,387.75	$3,414.32	$26.57	0.8%
44%	70.1-80	0.5%	75.2	24,069	$3,979.96	$4,009.39	$29.43	0.7%
44%	80.1-90	0.4%	84.7	27,000	$4,464.59	$4,497.59	$33.00	0.7%
41%	90.1-100	0.3%	94.4	28,369	$4,745.98	$4,786.32	$40.35	0.9%
45%	100.1-120	0.4%	109.2	35,732	$5,869.22	$5,908.84	$39.62	0.7%
45%	120.1-140	0.2%	129.0	42,752	$6,998.78	$7,043.75	$44.98	0.6%
43%	140.1-160	0.1%	149.1	46,963	$7,762.33	$7,819.39	$57.06	0.7%
40%	160.1-200	0.1%	175.7	51,679	$8,660.41	$8,735.45	$75.04	0.9%
26%	200.1+	0.0%	348.8	66,522	$12,422.12	$12,650.29	$228.17	1.8%

Unitil Energy Systems, Inc.
Typical Bill Impacts as a Result of Proposed Rates
Impact on G2 Rate Customers

Unitil Energy Systems, Inc. Rates - Effective 12/1/2020:		**Unitil Energy Systems, Inc. Rates - Proposed:**	
Customer Charge	**$29.19**	Customer Charge	**$ 32.20**
	All kW		**All kW**
Distribution Charge	$10.51	Distribution Charge	$ 11.59
Stranded Cost Charge	($0.05)	Stranded Cost Charge	($0.05)
TOTAL	**$10.46**	**TOTAL**	**$11.54**
	kWh		**kWh**
Distribution Charge	$0.00000	Distribution Charge	$0.00000
External Delivery Charge	$0.03613	External Delivery Charge [1]	$0.03478
Stranded Cost Charge	($0.00005)	Stranded Cost Charge	($0.00005)
System Benefits Charge	$0.00752	System Benefits Charge [1]	$0.00659
Storm Recovery Adjustment Factor	$0.00084	Storm Recovery Adjustment Factor	$0.00084
Fixed Default Service Charge	$0.08702	Fixed Default Service Charge	$0.08702
TOTAL	**$0.13146**	**TOTAL**	**$0.12918**

Note [1]: Present rates adjusted to reflect costs moving into base distribution charge rates

Unitil Energy Systems, Inc.
Typical Bill Impacts as a Result of Proposed Rates
Impact on G2 - kWh meter Rate Customers

Range Monthly kWh	Percentage Bills	Average Monthly kWh	Total Bill Using Rates Effective 12/1/2020	Total Bill Using Rates Proposed	Total Difference	% Total Difference
0-50	58.8%	18	$20.93	$22.80	$1.87	9.0%
51-100	16.6%	71	$28.33	$30.14	$1.80	6.4%
101-200	13.3%	146	$38.84	$40.54	$1.70	4.4%
201-300	4.8%	243	$52.36	$53.93	$1.57	3.0%
301-400	2.3%	346	$66.87	$68.29	$1.43	2.1%
401-500	1.3%	452	$81.71	$82.99	$1.28	1.6%
501-600	1.1%	543	$94.44	$95.60	$1.16	1.2%
601-700	0.6%	639	$107.87	$108.90	$1.02	1.0%
701-800	0.3%	742	$122.30	$123.19	$0.88	0.7%
801-1,000	0.3%	890	$142.99	$143.68	$0.68	0.5%
1,000+	0.7%	2,084	$310.31	$309.35	($0.95)	-0.3%

Unitil Energy Systems, Inc.
Rates - Effective 12/1/2020:

Customer Charge	**$18.38**
	All kWh
Distribution Charge	$0.00883
External Delivery Charge	$0.03613
Stranded Cost Charge	($0.00025)
System Benefits Charge	$0.00752
Storm Recovery Adjustment Factor	$0.00084
Fixed Default Service Charge	$0.08702
TOTAL	**$0.14009**

Unitil Energy Systems, Inc.
Rates - Proposed:

Customer Charge	**$20.28**
	All kWh
Distribution Charge	$0.00974
External Delivery Charge [1]	$0.03478
Stranded Cost Charge	($0.00025)
System Benefits Charge [1]	$0.00659
Storm Recovery Adjustment Factor	$0.00084
Fixed Default Service Charge	$0.08702
TOTAL	**$0.13872**

Note [1]: Present rates adjusted to reflect costs moving into base distribution charge rates

Unitil Energy Systems, Inc.
Typical Bill Impacts as a Result of Proposed Rates
Impact on G2 - QRWH and SH Rate Customers

Range Monthly kWh	Percentage Bills	Average kWh	Total Bill Using Rates Effective 12/1/2020	Total Bill Using Rates Proposed	Total Difference	% Total Difference
0-250	41.9%	79	$22.65	$23.74	$1.09	4.8%
251-500	13.0%	365	$69.39	$70.77	$1.38	2.0%
501-750	8.0%	624	$111.66	$113.31	$1.65	1.5%
751-1,000	5.5%	869	$151.56	$153.46	$1.90	1.3%
1,001-2,000	12.5%	1,415	$240.83	$243.30	$2.47	1.0%
2,001-3,000	7.1%	2,448	$409.46	$412.99	$3.53	0.9%
3,001-4,000	3.5%	3,453	$573.56	$578.13	$4.57	0.8%
4,001-5,000	2.3%	4,506	$745.59	$751.25	$5.66	0.8%
5,001-6,000	1.0%	5,516	$910.42	$917.12	$6.70	0.7%
6,001-7,000	0.9%	6,474	$1,067.00	$1,074.69	$7.69	0.7%
7,001-8,000	0.9%	7,429	$1,222.92	$1,231.59	$8.68	0.7%
8,001-9,000	0.4%	8,471	$1,392.98	$1,402.73	$9.75	0.7%
9,001-10,000	0.5%	9,612	$1,579.40	$1,590.33	$10.93	0.7%
10,001+	2.6%	18,764	$3,073.89	$3,094.27	$20.38	0.7%

Unitil Energy Systems, Inc.
Rates - Effective 12/1/2020:

Customer Charge	**$9.73**
	All kWh
Distribution Charge	$0.03204
External Delivery Charge	$0.03613
Stranded Cost Charge	($0.00025)
System Benefits Charge	$0.00752
Storm Recovery Adjustment Factor	$0.00084
Fixed Default Service Charge	$0.08702
TOTAL	**$0.16330**

Unitil Energy Systems, Inc.
Rates - Proposed:

Customer Charge	**$10.73**
	All kWh
Distribution Charge	$0.03535
Ext External Delivery Charge [1]	$0.03478
Stranded Cost Charge	($0.00025)
Sys System Benefits Charge [1]	$0.00659
Storm Recovery Adjustment Factor	$0.00084
Fixed Default Service Charge	$0.08702
TOTAL	**$0.16433**

Note [1]: Present rates adjusted to reflect costs moving into base distribution charge rates

Unitil Energy Systems, Inc.
Typical Bill Impacts as a Result of Proposed Rates
Impact on G1 Rate Customers

Customer	Load Factor	Average Monthly kVA	Average kWh	Voltage Discount Tier	Transformer Ownership Credit	Total Bill Using Rates Effective 12/1/2020	Total Bill Using Rates Proposed	Total Difference	% Total Difference
1	32.0%	291	67,950		Yes	$11,060.75	$11,437.84	$377.10	3.4%
2	40.1%	158	46,305	1	Yes	$7,089.30	$7,269.60	$180.30	2.5%
3	20.3%	489	72,292		Yes	$13,018.01	$13,735.15	$717.14	5.5%
4	15.5%	567	64,125			$12,786.49	$13,093.53	$307.04	2.4%
5	16.8%	193	23,717		Yes	$4,611.28	$4,916.01	$304.73	6.6%
6	33.2%	288	69,841	1	Yes	$10,986.64	$11,339.00	$352.36	3.2%
7	40.1%	290	84,900			$13,404.46	$13,450.98	$46.52	0.3%
8	24.8%	316	57,185			$9,996.30	$10,126.51	$130.21	1.3%
9	49.2%	186	66,885	1	Yes	$9,906.91	$10,089.27	$182.36	1.8%
10	29.4%	673	144,575	1	Yes	$23,184.57	$24,038.75	$854.18	3.7%
11	57.5%	450	189,070			$28,180.03	$28,112.73	($67.31)	-0.2%
12	44.0%	322	103,375			$16,053.68	$16,082.95	$29.27	0.2%
13	36.9%	451	121,500			$19,387.76	$19,475.16	$87.40	0.5%
14	52.9%	318	123,050			$18,588.82	$18,570.49	($18.33)	-0.1%
15	42.0%	291	89,400			$14,002.79	$14,040.32	$37.52	0.3%
16	23.2%	459	77,850			$13,759.96	$13,952.61	$192.65	1.4%
17	53.7%	716	280,803	1	Yes	$40,867.83	$41,492.32	$624.49	1.5%
18	70.0%	538	275,100			$40,048.98	$39,853.59	($195.39)	-0.5%
19	66.9%	1,432	699,283	2	Yes	$97,705.19	$98,624.02	$918.83	0.9%
20	26.6%	640	124,101	1	Yes	$20,341.65	$21,183.76	$842.11	4.1%
21	50.9%	254	94,302	1	Yes	$13,874.29	$14,113.12	$238.83	1.7%
22	21.6%	228	35,933	1	Yes	$6,247.65	$6,572.32	$324.67	5.2%
23	55.0%	495	198,707			$29,773.41	$29,718.70	($54.71)	-0.2%
24	57.4%	420	175,773			$26,219.25	$26,158.83	($60.41)	-0.2%
25	35.7%	293	76,309	1	Yes	$11,846.91	$12,193.56	$346.65	2.9%
26	62.3%	558	254,016	2	Yes	$35,804.18	$36,208.37	$404.19	1.1%
27	49.8%	692	251,233		Yes	$37,752.38	$38,421.27	$668.89	1.8%
28	34.1%	379	94,439	1	Yes	$14,758.06	$15,214.38	$456.32	3.1%
29	14.6%	274	29,187		Yes	$5,894.70	$6,330.53	$435.83	7.4%
30	42.8%	179	55,967			$8,802.57	$8,829.86	$27.29	0.3%

Unitil Energy Systems, Inc.
Typical Bill Impacts as a Result of Proposed Rates
Impact on G1 Rate Customers

Customer	Load Factor	Average Monthly kVA	Average kWh	Voltage Discount Tier	Transformer Ownership Credit	Total Bill Using Rates Effective 12/1/2020	Total Bill Using Rates Proposed	Total Difference	% Total Difference
31	21.9%	468	74,603	1	Yes	$12,834.46	$13,487.99	$653.53	5.1%
32	25.4%	392	72,567			$12,568.69	$12,721.99	$153.30	1.2%
33	37.9%	218	60,330			$9,661.83	$9,708.90	$47.06	0.5%
34	54.1%	2,781	1,099,095	2	Yes	$157,112.29	$159,454.98	$2,342.69	1.5%
35	45.5%	277	91,980			$14,228.22	$14,248.58	$20.36	0.1%
36	58.4%	561	238,900			$35,502.69	$35,406.94	($95.75)	-0.3%
37	57.5%	429	180,133	2	Yes	$25,642.65	$25,989.02	$346.37	1.4%
38	36.9%	342	92,233			$14,755.09	$14,825.30	$70.21	0.5%
39	22.2%	382	62,000		Yes	$10,925.40	$11,476.85	$551.45	5.0%
40	32.6%	227	53,960			$8,898.12	$8,966.42	$68.30	0.8%
41	69.3%	2,259	1,143,565	2	Yes	$159,159.15	$160,513.51	$1,354.36	0.9%
42	61.5%	1,286	577,482	2	Yes	$81,401.66	$82,337.92	$936.26	1.2%
43	62.8%	2,917	1,336,786	2		$189,321.97	$188,560.64	($761.33)	-0.4%
44	36.1%	498	131,232	1	Yes	$20,272.73	$20,852.75	$580.03	2.9%
45	25.4%	431	79,983			$13,828.20	$13,994.58	$166.39	1.2%
46	53.6%	1,072	419,655	2	Yes	$60,111.19	$61,028.64	$917.44	1.5%
47	65.3%	644	307,000			$44,999.74	$44,813.00	($186.74)	-0.4%
48	51.5%	159	59,867			$9,159.52	$9,162.50	$2.98	0.0%
49	25.0%	133	24,333			$4,336.18	$4,400.13	$63.95	1.5%
50	22.6%	246	40,675			$7,316.92	$7,430.70	$113.78	1.6%
51	22.0%	397	63,750			$11,454.59	$11,631.46	$176.87	1.5%
52	16.5%	372	44,875			$8,809.70	$9,010.49	$200.80	2.3%
53	57.7%	762	320,917			$47,704.98	$47,577.71	($127.26)	-0.3%
54	40.5%	183	54,200			$8,603.02	$8,637.45	$34.43	0.4%
55	53.2%	695	270,150			$40,588.83	$40,525.68	($63.15)	-0.2%
56	48.6%	199	70,633			$10,862.68	$10,871.87	$9.19	0.1%
57	48.2%	243	85,567			$13,139.61	$13,148.70	$9.09	0.1%
58	51.0%	315	117,293			$17,815.26	$17,807.60	($7.66)	0.0%
59	33.1%	333	80,643			$13,178.69	$13,268.46	$89.78	0.7%
60	31.4%	389	89,200			$14,715.29	$14,828.69	$113.40	0.8%

Unitil Energy Systems, Inc.
Typical Bill Impacts as a Result of Proposed Rates
Impact on G1 Rate Customers

Customer	Load Factor	Average Monthly kVA	Average kWh	Voltage Discount Tier	Transformer Ownership Credit	Total Bill Using Rates Effective 12/1/2020	Total Bill Using Rates Proposed	Total Difference	% Total Difference
61	45.3%	325	107,333			$16,590.08	$16,612.46	$22.38	0.1%
62	23.2%	1,393	236,250		Yes	$40,734.58	$42,678.01	$1,943.43	4.8%
63	21.5%	482	75,480			$13,625.22	$13,841.02	$215.81	1.6%
64	41.2%	297	89,533			$14,065.15	$14,106.96	$41.82	0.3%
65	47.8%	259	90,500			$13,903.14	$13,913.35	$10.21	0.1%
66	41.3%	154	46,583			$7,393.18	$7,422.71	$29.53	0.4%
67	7.5%	373	20,342			$5,621.95	$5,879.39	$257.43	4.6%
68	44.8%	355	115,887			$17,928.94	$17,954.81	$25.87	0.1%
69	55.6%	520	211,000			$31,560.35	$31,496.63	($63.72)	-0.2%
70	32.0%	372	86,900			$14,286.24	$14,391.65	$105.41	0.7%
71	51.4%	280	105,200			$15,977.71	$15,970.78	($6.92)	0.0%
72	48.5%	465	164,567			$25,102.13	$25,102.21	$0.08	0.0%
73	54.1%	409	161,410			$24,266.38	$24,230.29	($36.10)	-0.1%
74	38.3%	166	46,470			$7,468.46	$7,507.44	$38.98	0.5%
75	76.1%	476	264,430			$38,192.85	$37,974.12	($218.72)	-0.6%
76	55.2%	354	142,383			$21,371.58	$21,336.25	($35.33)	-0.2%
77	49.6%	252	91,333			$13,960.91	$13,964.04	$3.13	0.0%
78	33.0%	212	51,093			$8,414.99	$8,478.61	$63.62	0.8%
79	51.3%	328	122,880			$18,640.07	$18,629.62	($10.45)	-0.1%
80	58.8%	678	291,100			$43,188.92	$43,064.95	($123.97)	-0.3%
81	12.5%	681	62,090			$13,381.86	$13,781.41	$399.54	3.0%
82	33.0%	192	46,390			$7,655.28	$7,714.58	$59.31	0.8%
83	52.5%	249	95,583			$14,490.30	$14,481.29	($9.01)	-0.1%
84	12.6%	838	76,750			$16,473.10	$16,959.96	$486.86	3.0%
85	61.7%	257	115,933			$17,202.13	$17,153.05	($49.08)	-0.3%
86	17.5%	633	80,900			$15,472.80	$15,792.85	$320.06	2.1%
87	4.7%	180	6,192	2		$2,171.51	$2,300.28	$128.78	5.9%
88	21.1%	241	37,150			$6,818.05	$6,935.80	$117.75	1.7%
89	60.6%	489	216,067			$31,986.18	$31,887.02	($99.17)	-0.3%
90	56.2%	1,044	428,000			$63,773.64	$63,619.22	($154.42)	-0.2%

Unitil Energy Systems, Inc.
Typical Bill Impacts as a Result of Proposed Rates
Impact on G1 Rate Customers

Customer	Load Factor	Average Monthly kVA	Average kWh	Voltage Discount Tier	Transformer Ownership Credit	Total Bill Using Rates Effective 12/1/2020	Total Bill Using Rates Proposed	Total Difference	% Total Difference
91	26.8%	360	70,500			$12,058.50	$12,191.89	$133.39	1.1%
92	17.5%	321	41,007			$7,926.50	$8,097.36	$170.86	2.2%
93	39.4%	311	89,520			$14,167.78	$14,220.28	$52.50	0.4%
94	67.4%	501	246,680			$36,067.89	$35,908.67	($159.22)	-0.4%
95	25.8%	222	41,900			$7,294.81	$7,387.25	$92.44	1.3%
96	64.7%	354	167,040			$24,583.36	$24,491.93	($91.43)	-0.4%
97	42.0%	297	91,080			$14,262.94	$14,300.86	$37.92	0.3%
98	20.0%	230	33,520			$6,259.57	$6,376.83	$117.26	1.9%
99	11.0%	250	20,064			$4,657.43	$4,820.69	$163.26	3.5%
100	21.8%	228	36,187			$6,593.43	$6,703.25	$109.81	1.7%
101	47.6%	476	165,320			$25,284.00	$25,290.92	$6.92	0.0%
102	55.4%	356	143,928			$21,590.47	$21,553.44	($37.03)	-0.2%
103	37.7%	381	104,773	2	Yes	$15,839.98	$16,268.69	$428.71	2.7%
104	34.6%	376	94,929	1	Yes	$14,794.04	$15,242.59	$448.55	3.0%
105	70.3%	321	164,820			$24,049.87	$23,938.54	($111.33)	-0.5%
106	33.7%	258	63,456			$10,368.93	$10,439.51	$70.58	0.7%
107	19.7%	271	39,008			$7,284.98	$7,421.46	$136.49	1.9%
108	54.3%	257	102,032			$15,392.19	$15,374.82	($17.37)	-0.1%
109	42.3%	239	73,700			$11,561.11	$11,593.85	$32.75	0.3%
110	48.6%	770	273,155	2	Yes	$39,647.60	$40,371.26	$723.67	1.8%
111	37.3%	295	80,320			$12,846.98	$12,907.92	$60.94	0.5%
112	40.2%	368	107,900			$16,988.79	$17,043.06	$54.27	0.3%
113	51.3%	264	99,073	2	Yes	$14,333.79	$14,576.44	$242.65	1.7%
114	30.6%	339	75,583			$12,559.26	$12,664.60	$105.34	0.8%
115	61.0%	677	301,440			$44,526.49	$44,378.04	($148.45)	-0.3%
116	74.4%	405	219,800			$31,839.55	$31,667.26	($172.30)	-0.5%
117	61.5%	217	97,536			$14,503.27	$14,465.16	($38.11)	-0.3%
118	28.4%	352	73,100			$12,339.07	$12,460.61	$121.54	1.0%
119	48.2%	453	159,340			$24,331.75	$24,334.58	$2.83	0.0%
120	43.9%	346	110,840			$17,208.33	$17,239.22	$30.89	0.2%

Unitil Energy Systems, Inc.
Typical Bill Impacts as a Result of Proposed Rates
Impact on G1 Rate Customers

Customer	Load Factor	Average Monthly kVA	Average kWh	Voltage Discount Tier	Transformer Ownership Credit	Total Bill Using Rates Effective 12/1/2020	Total Bill Using Rates Proposed	Total Difference	% Total Difference
121	51.2%	684	255,424	2		$37,165.57	$37,121.41	($44.16)	-0.1%
122	40.9%	249	74,387			$11,729.83	$11,769.11	$39.28	0.3%
123	20.1%	236	34,573			$6,441.50	$6,560.93	$119.43	1.9%
124	9.8%	606	43,345	2	Yes	$9,649.96	$10,598.44	$948.48	9.8%
125	18.9%	312	43,030			$8,116.50	$8,275.25	$158.75	2.0%
126	60.0%	639	279,650			$41,398.84	$41,270.42	($128.42)	-0.3%
127	52.4%	2,025	774,292	2	Yes	$111,156.34	$112,922.01	$1,765.67	1.6%
128	61.2%	2,222	991,779	2	Yes	$139,828.23	$141,452.28	$1,624.05	1.2%
129	42.8%	137	42,708			$6,755.29	$6,780.04	$24.75	0.4%
130	48.5%	206	72,800			$11,194.13	$11,203.42	$9.29	0.1%
131	27.1%	308	60,960			$10,422.86	$10,537.83	$114.97	1.1%
132	32.2%	174	41,024			$6,820.18	$6,877.80	$57.61	0.8%
133	48.5%	1,145	405,120			$61,561.01	$61,537.05	($23.96)	0.0%
134	16.0%	249	29,000			$5,814.34	$5,956.54	$142.20	2.4%
135	48.6%	431	152,940			$23,333.28	$23,333.83	$0.56	0.0%
136	31.7%	483	111,872			$18,376.41	$18,510.51	$134.10	0.7%
137	44.2%	242	78,120			$12,163.16	$12,188.53	$25.38	0.2%
138	61.1%	543	242,600			$35,856.21	$35,738.92	($117.28)	-0.3%
139	48.8%	941	335,067			$50,897.91	$50,876.29	($21.62)	0.0%
140	80.1%	152	89,145			$12,922.09	$12,853.22	($68.87)	-0.5%
141	54.2%	427	168,907			$25,379.03	$25,339.78	($39.25)	-0.2%
142	36.7%	319	85,493			$13,700.84	$13,768.38	$67.55	0.5%
143	26.8%	637	124,693			$21,206.85	$21,430.28	$223.42	1.1%
144	55.0%	424	170,000			$25,497.93	$25,453.79	($44.14)	-0.2%
145	45.1%	355	116,783			$18,048.68	$18,072.80	$24.13	0.1%
146	25.7%	401	75,167			$12,977.44	$13,131.97	$154.54	1.2%
147	58.8%	477	204,500			$30,389.89	$30,307.89	($82.00)	-0.3%
148	27.0%	849	167,400			$28,365.31	$28,654.50	$289.18	1.0%
149	70.7%	1,008	519,800			$75,458.24	$75,067.02	($391.21)	-0.5%
150	55.6%	457	185,400			$27,753.07	$27,699.33	($53.74)	-0.2%

Unitil Energy Systems, Inc.
Typical Bill Impacts as a Result of Proposed Rates
Impact on G1 Rate Customers

Customer	Load Factor	Average Monthly kVA	Average kWh	Voltage Discount Tier	Transformer Ownership Credit	Total Bill Using Rates Effective 12/1/2020	Total Bill Using Rates Proposed	Total Difference	% Total Difference
151	42.1%	144	44,240			$7,009.32	$7,036.15	$26.83	0.4%
152	6.3%	310	14,317			$4,367.32	$4,590.49	$223.17	5.1%
153	61.1%	885	394,833			$58,261.88	$58,061.25	($200.63)	-0.3%
154	51.7%	511	192,725			$29,113.11	$29,084.15	($28.96)	-0.1%
155	45.8%	562	187,767			$28,852.76	$28,874.45	$21.69	0.1%
156	26.2%	318	60,750			$10,468.78	$10,591.70	$122.93	1.2%
157	48.6%	610	216,075			$32,899.54	$32,893.52	($6.02)	0.0%
158	10.9%	492	39,030			$8,956.01	$9,262.80	$306.79	3.4%
159	68.6%	1,016	508,947	2	Yes	$70,957.43	$71,584.05	$626.62	0.9%
160	36.0%	78	20,350			$3,396.98	$3,427.06	$30.09	0.9%
161	3.4%	3,066	75,994	2		$31,945.61	$34,065.68	$2,120.07	6.6%
162	3.9%	255	7,292			$3,034.55	$3,231.04	$196.49	6.5%
163	58.2%	225	95,529			$14,299.67	$14,272.05	($27.63)	-0.2%
164	58.8%	295	126,875			$18,914.07	$18,869.37	($44.70)	-0.2%
165	42.2%	181	55,800			$8,793.81	$8,822.80	$28.99	0.3%
166	2.3%	745	12,588	1	Yes	$6,830.34	$8,102.76	$1,272.42	18.6%
167	34.5%	381	95,900			$15,523.62	$15,615.19	$91.58	0.6%

Unitil Energy Systems, Inc.
Typical Bill Impacts as a Result of Proposed Rates
Impact on G1 Rate Customers

Customer	Load Factor	Average Monthly kVA	Average kWh	Voltage Discount Tier	Transformer Ownership Credit	Total Bill Using Rates Effective 12/1/2020	Total Bill Using Rates Proposed	Total Difference	% Total Difference

Unitil Energy Systems, Inc.		**Unitil Energy Systems, Inc.**	
Rates - Effective 12/1/2020:		**Rates - Proposed:**	
Customer Charge - Secondary	**$162.18**	Customer Charge - Secondary	**$ 178.93**
Customer Charge - Primary	**$86.49**	Customer Charge - Primary	**$ 95.42**
	All kVA		**All kVA**
Distribution Charge	$7.60	Distribution Charge	$ 8.37
Stranded Cost Charge	($0.06)	Stranded Cost Charge	($0.06)
TOTAL	**$7.54**	**TOTAL**	**$8.31**
	All kWh		**All kWh**
Distribution Charge	$0.00000	Distribution Charge	$0.00000
External Delivery Charge	$0.03613	External Delivery Charge [1]	$0.03478
Stranded Cost Charge	($0.00006)	Stranded Cost Charge	($0.00006)
System Benefits Charge	$0.00752	System Benefits Charge [1]	$0.00659
Storm Recovery Adjustment Factor	$0.00084	Storm Recovery Adjustment Factor	$0.00084
Avg Dec 20 - Apr 21 Default Srvc Charge	$0.08581	Avg Dec 20 - Apr 21 Default Srvc Charge	$0.08581
TOTAL	**$0.13024**	**TOTAL**	**$0.12796**
High Voltage Discount 1 for 4-13.8 kV	2.0%	High Voltage Discount 1 for 4-13.8 kV	2.0%
High Voltage Discount 2 for 34.5 kV	3.5%	High Voltage Discount 2 for 34.5 kV	3.5%
Transformer Ownership Credit $/kVA	$0.50	Transformer Ownership Credit $/kVA	$ (0.50)

Unitil Energy Systems, Inc.
Typical Bill Impacts as a Result of Proposed Rates
Impact on Tariffed OL Rate Customers

	Nominal Watts	Lumens	Type	Current Average Monthly kWh	Percentage of Lights	Total Bill Using Rates Effective 12/1/2020	Total Bill Using Rates Proposed	Total Difference	% Total Difference
	Mercury Vapor:								
1	100	3,500	ST	43	14.2%	$18.92	$19.27	$0.35	1.8%
2	175	7,000	ST	71	0.8%	$25.07	$24.89	($0.18)	-0.7%
3	250	11,000	ST	100	0.8%	$30.98	$30.15	($0.82)	-2.7%
4	400	20,000	ST	157	1.3%	$41.86	$37.50	($4.35)	-10.4%
5	1,000	60,000	ST	372	0.0%	$91.02	$72.77	($18.25)	-20.1%
6	250	11,000	FL	100	0.7%	$32.15	$31.15	($0.99)	-3.1%
7	400	20,000	FL	157	0.9%	$43.36	$41.82	($1.53)	-3.5%
8	1,000	60,000	FL	380	0.1%	$87.58	$74.30	($13.28)	-15.2%
9	100	3,500	PB	48	4.0%	$19.71	$19.63	($0.08)	-0.4%
10	175	7000	PB	71	0.6%	$24.19	$23.81	($0.38)	-1.6%
	High Pressure Sodium:								
11	50	4,000	ST	23	36.7%	$16.54	$16.69	$0.16	0.9%
12	100	9,500	ST	48	1.3%	$21.52	$21.93	$0.41	1.9%
13	150	16,000	ST	65	4.0%	$23.81	$25.64	$1.83	7.7%
14	250	30,000	ST	102	13.2%	$32.53	$32.69	$0.16	0.5%
15	400	50,000	ST	161	2.8%	$45.26	$45.55	$0.29	0.6%
16	1,000	140,000	ST	380	1.6%	$91.54	$91.52	($0.02)	0.0%
17	150	16,000	FL	65	2.7%	$26.14	$26.64	$0.50	1.9%
18	250	30,000	FL	102	3.9%	$34.15	$34.73	$0.58	1.7%
19	400	50,000	FL	161	5.0%	$44.71	$46.05	$1.34	3.0%
20	1,000	140,000	FL	380	2.5%	$91.91	$91.90	($0.01)	0.0%
21	50	4,000	PB	23	1.4%	$15.53	$16.41	$0.88	5.7%
22	100	9,500	PB	48	0.9%	$20.34	$20.84	$0.50	2.5%
	Metal Halide								
23	175	8,800	ST	74	0.0%	$29.62	$26.80	($2.82)	-9.5%
24	250	13,500	ST	102	0.0%	$35.04	Discontinued	NA	NA
25	400	23,500	ST	158	0.0%	$43.19	Discontinued	NA	NA
26	175	8,800	FL	74	0.0%	$32.71	Discontinued	NA	NA
27	250	13,500	FL	102	0.0%	$38.22	Discontinued	NA	NA
28	400	23,500	FL	158	0.0%	$45.62	Discontinued	NA	NA
29	1,000	86,000	FL	374	0.5%	$81.31	$73.53	($7.78)	-9.6%
30	175	8,800	PB	74	0.0%	$28.34	Discontinued	NA	NA
31	250	13,500	PB	102	0.0%	$33.20	Discontinued	NA	NA
32	400	23,500	PB	158	0.0%	$41.91	Discontinued	NA	NA
	LED								
33	42	3,600	AL	15	0.0%	$15.13	Discontinued	NA	NA
34	57	5,200	AL	20	0.0%	$15.84	Discontinued	NA	NA
35	25	3,000	ST	9	0.0%	$14.29	Discontinued	NA	NA
36	88	8,300	ST	30	0.0%	$17.24	Discontinued	NA	NA
37	108	11,500	ST	37	0.0%	$18.22	Discontinued	NA	NA
38	193	21,000	ST	67	0.0%	$22.41	Discontinued	NA	NA
39	123	12,180	FL	43	0.0%	$19.05	Discontinued	NA	NA
40	194	25,700	FL	67	0.0%	$22.41	Discontinued	NA	NA
41	297	38,100	FL	103	0.0%	$27.45	Discontinued	NA	NA

Unitil Energy Systems, Inc.
Typical Bill Impacts as a Result of Proposed Rates
Impact on Tariffed OL Rate Customers

Unitil Energy Systems, Inc.
Rates - Effective 12/1/2020:

Customer Charge	**$0.00**
	All kWh
Distribution Charge	$0.00000
External Delivery Charge	$0.03613
Stranded Cost Charge	($0.00025)
System Benefits Charge	$0.00752
Storm Recovery Adjustment Factor	$0.00084
Fixed Default Service Charge	$0.08702
TOTAL	**$0.13126**

Unitil Energy Systems, Inc.
Rates - Proposed:

Customer Charge	**$0.00**
	All kWh
Distribution Charge	$0.00000
External Delivery Charge [1]	$0.03478
Stranded Cost Charge	($0.00025)
System Benefits Charge [1]	$0.00659
Storm Recovery Adjustment Factor	$0.00084
Fixed Default Service Charge	$0.08702
TOTAL	**$0.12898**

Note [1]: Present rates adjusted to reflect costs moving into base distribution charge rates

Luminaire Charges: (Rates - Effective 12/1/2020)

	Mercury Vapor Rate/Mo.		Sodium Vapor Rate/Mo.		Metal Halide Rate/Mo.		LED Rate/Mo.
1	$13.28	#	$13.52	#	$19.91	33	$13.16
2	$15.75	#	$15.22	#	$21.65	34	$13.21
3	$17.85	#	$15.28	#	$22.45	35	$13.11
4	$21.25	#	$19.14	#	$23.00	36	$13.30
5	$42.19	#	$24.13	#	$24.83	37	$13.36
6	$19.02	#	$41.66	#	$24.88	38	$13.62
7	$22.75	#	$17.61	#	$32.22	39	$13.41
8	$37.70	#	$20.76	#	$18.63	40	$13.62
9	$13.41	#	$23.58	#	$19.81	41	$13.93
10	$14.87	#	$42.03	#	$21.17		
		#	$12.51				
		#	$14.04				

Luminaire Charges: (Rates - Proposed)

	Mercury Vapor Rate/Mo.		Sodium Vapor Rate/Mo.		Metal Halide Rate/Mo.		LED Rate/Mo.
1	$13.73	11	$13.73	23	$17.25	33	Discontinued
2	$15.73	12	$15.73	24	Discontinued	34	Discontinued
3	$17.25	13	$17.25	25	Discontinued	35	Discontinued
4	$17.25	14	$19.53	26	Discontinued	36	Discontinued
5	$24.78	15	$24.78	27	Discontinued	37	Discontinued
6	$18.25	16	$42.51	28	Discontinued	38	Discontinued
7	$21.57	17	$18.25	29	$25.29	39	Discontinued
8	$25.29	18	$21.57	30	Discontinued	40	Discontinued
9	$13.44	19	$25.29	31	Discontinued	41	Discontinued
#	$14.65	20	$42.89	32	Discontinued		
		21	$13.44				
		22	$14.65				

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY

OF

TIMOTHY S. LYONS

EXHIBIT TSL-1

New Hampshire Public Utilities Commission

Docket No. DE 21-030

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name, occupation and business address.

A. My name is Timothy S. Lyons. I am a Partner with ScottMadden, Inc. My business address is 1900 West Park Drive, Suite 250, Westborough, Massachusetts 01581.

Q. On whose behalf are you submitting this testimony?

A. I am submitting this testimony on behalf of Unitil Energy Systems, Inc. ("UES" or the "Company").

Q. Please describe your professional experience.

A. I have more than 30 years of experience in the energy industry. I started my career in 1985 at Boston Gas Company, eventually becoming Director of Rates and Revenue Analysis. In 1993, I moved to Providence Gas Company, eventually becoming Vice President of Marketing and Regulatory Affairs. Starting in 2001, I held a number of management consulting positions in the energy industry first at KEMA and then at Quantec, LLC. In 2005, I became Vice President of Sales and Marketing at Vermont Gas Systems, Inc. before joining Sussex Economic Advisors, LLC ("Sussex") in 2013. Sussex was acquired by ScottMadden in 2016.

Q. What is your educational background?

A. I hold a bachelor's degree from St. Anselm College, a master's degree in Economics from The Pennsylvania State University, and a master's degree in

Business Administration from Babson College. A summary of my professional and educational background, including a list of my testimony in prior proceedings, is included in Schedule TSL-1.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor the Company's proposed revenue decoupling mechanism ("RDM") and associated tariff. The RDM addresses the basic misalignment between the structure of the Company's costs and its rates. Specifically, utility distribution costs are largely fixed and change very little in the short run with changes in usage levels. However, distribution rates have a significant variable or usage-based component that changes revenues (and cost recovery) with changes in usage levels. The RDM corrects for this misalignment by adjusting the Company's actual revenues to match its authorized revenues. RDMs have been approved in numerous jurisdictions, including New Hampshire, and are viewed in the industry as important to the development of Energy Efficiency ("EE") and Distributed Energy Resources ("DER") initiatives.

Q. How is the remaining portion of your testimony organized?

A. The remaining portion of my testimony is organized into the following sections.

- Section III provides an overview of revenue decoupling, including the Commission's guidance in the Gas and Electric Utilities Energy Efficiency Resource Standard proceeding ("EERS proceeding")[1]
- Section IV describes the proposed RDM.
- Section V illustrates the calculation of the proposed RDM for the residential rate class.

III. OVERVIEW OF REVENUE DECOUPLING

Q. What is revenue decoupling?

A. Revenue decoupling breaks or "decouples" the link between utility revenues and its sales volumes, helping to ensure that a utility does not over- or under-recover its authorized revenue requirement. There are two basic forms of revenue decoupling:

- Partial or Limited Revenue Decoupling – this type addresses specific variances between actual and authorized revenues, such as the impact of weather or EE. The Company's current lost revenue adjustment mechanism ("LRAM") is an example of partial or limited revenue decoupling.
- Full Revenue Decoupling – this type addresses the total variance between actual and authorized revenues. The Company's proposed RDM is an example of full revenue decoupling. Variances can be measured on the basis of total revenues or revenues per customer ("RPC").

[1] Docket DE 15-137

Q. Has the Commission approved a revenue decoupling mechanism for New Hampshire gas and electric utilities?

A. Yes. The Commission approved an LRAM, a partial or limited revenue decoupling mechanism, for all electric and gas utilities in the EERS proceeding,[2] noting:

> "…without the LRAM, or a change in the way rates are designed today, the utilities may lose revenue that the Commission has already determined in the utility's rate case is just and reasonable for them to recover. Consequently, we approve the LRAM as proposed."[3]

In the EERS proceeding, the Commission recognized the limitations of an LRAM and the role a full revenue decoupling mechanism can play in ensuring that the utility does not over- or under-recover its authorized revenue requirement.[4] The Commission therefore required utilities to seek approval of a revenue decoupling mechanism, stating:

> "We note that our approval of the LRAM does not limit our subsequent consideration and approval at any time of a different lost revenue recovery mechanism, and that the Joint Utilities (except NHEC) are required to seek approval of a decoupling or

[2] Docket DE 15-137, Order No 25,932
[3] Id., p. 59
[4] Id., p. 59-60 ("[W]e are mindful that, with an LRAM, the utilities' revenues can increase above their authorized revenue requirements from increased sales, and, for that reason and others, some parties prefer decoupling. This is because decoupling provides a reconciliation to the last-approved revenue requirement.")

> other lost-revenue recovery mechanism as an alternate to the LRAM in their first distribution rate cases after the first EERS triennium, if not before."[5]

Following the EERS proceeding, the Commission approved full revenue decoupling mechanisms for Liberty Utilities (EnergyNorth Natural Gas) Corporation,[6] and Liberty Utilities (Granite State Electric) Corporation.[7]

The Company's proposed RDM is generally consistent with the revenue decoupling mechanism approved for Liberty Utilities (Granite State Electric) Corporation.

Q. Please provide an overview of the Company's proposed RDM.

A. The proposed RDM is a full revenue decoupling mechanism that reconciles monthly actual and authorized RPC by rate class. The proposed RDM is applicable to all rate classes, except the lighting and proposed electric vehicle rate classes. The Company proposes that the authorized RPC be adjusted annually to reflect three estimated annual step increases on April 1, 2022 of $2.8 million, April 1, 2023 of $3.6 million, and April 1, 2024 of $3.3 million associated with 2021, 2022 and 2023 capital investments.

The proposed RDM process will consist of two steps:

In the first step, the Company will record monthly variances between actual and authorized RPC for each rate class. The monthly variances are then

[5] Id., p. 60
[6] Docket DE 17-048, Order No. 26,122
[7] Docket DE 19-064, Order No. 26,376

aggregated over the twelve-month period April through March (the "Measurement Period"). The monthly variances are recorded in a deferred account with carrying costs accrued at the Prime rate.[8] The aggregate variances and carrying costs form the basis for the revenue decoupling adjustment ("RDA") and the calculation of RDM adjustment factor ("RDAF") (surcharge or credit). For example, revenue shortfalls (i.e., actual RPC is less than authorized RPC) during the Measurement Period will result in a surcharge for the customers. Conversely, revenue surpluses (actual RPC is greater than authorized RPC) during the Measurement Period will result in a credit or refund to the customers.

In the second step, the Company will file with the Commission on June 1 the applicable RDAF. The filing will include an allocation of the RDA, including prior period reconciliation and deferrals as a result of a cap, to each rate class, and calculation of the RDAF.

The RDA is allocated to each rate class based on the authorized revenues of each rate class in the most recent rate case, including step adjustments.

The RDAF is calculated as a dollar per kWh charge or credit based on the RDA allocated to each rate class divided by the projected kWh sales for each rate class over the prospective twelve-month period August through July ("RDM Adjustment Period"). The RDAF will be charged or credited to customer bills during the RDM Adjustment Period.

[8] Interest shall be calculated at the prime rate, with said prime rate to be fixed on a quarterly basis and to be established as reported in the Wall Street Journal on the first business day of the month preceding the calendar quarter. If more than one interest rate is reported, the average of the reported rates shall be used.

The tariff for the Company's proposed RDM is included in Schedule TSL-2. Upon implementation of its first RDAF, UES will incorporate the supporting RDAF calculation in its RDAC tariff.

Q. What are the primary benefits of the Company's proposed RDM?

A. There are three primary benefits of the Company's proposed RDM:

1. It corrects the basic misalignment between utility rates and costs;
2. It supports achievement of certain policy objectives, such as EE and DER initiatives; and
3. It helps stabilize utility cost recovery as well as customer bills.

Q. Please discuss the basic misalignment between utility rates and costs.

A. Electric utilities incur three types of costs in providing electric service to customers:

- <u>Customer costs</u> – including meter, billing and a portion of distribution costs that generally vary by the number of customers;
- <u>Demand-related costs</u> – including transmission and distribution costs that generally vary by demand; and
- <u>Energy-related costs</u> – including variable O&M expenses that generally vary by kWh sales or energy consumed.

Utility revenue requirements and rates are designed to recover all of these costs. However, especially for residential customers, a significant portion of the revenue requirements are recovered on the basis of kWh consumption charges reflecting usage at the time rates are established (i.e., rates are set based on an assumed level of usage). Thus, to the extent that actual usage is significantly lower than the assumed level of usage in rates, the utility rates no longer recover the authorized revenue requirements. Conversely, to the extent that actual usage is significantly higher than the assumed level of usage in rates, then utility rates recover more than the authorized revenue requirements.

Revenue decoupling corrects for this misalignment by adjusting revenues to match the authorized revenue requirements.

Q. Has the Commission recognized this misalignment between utility rates and costs?

A. Yes. In the EERS proceeding, the Commission noted this misalignment in the context of energy savings due to EE programs. The Commission stated:

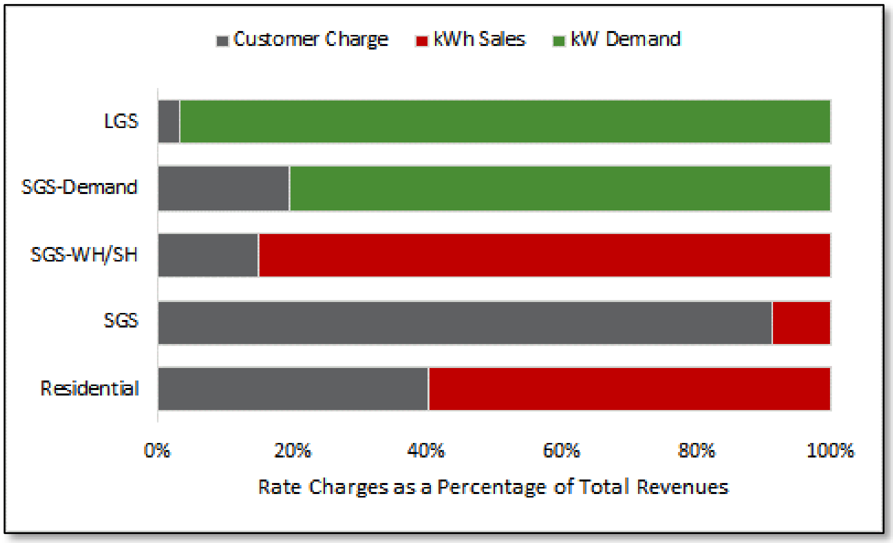
> "With increased energy savings comes decreased utility revenues due to standard rate design, which recovers costs through a variable, or consumption-based, rate."[9]

Q. Do the Company's current rates exhibit this misalignment between utility costs and rates?

A. Yes. The portion of the Company's charges that are based on consumption (kWh sales or kW demand) is significant, as shown in Figure 1.

[9] Docket DE 15-137, Order No 25,932, p. 59

Figure 1: Consumption Revenues as Percentage of Total Revenues[10]



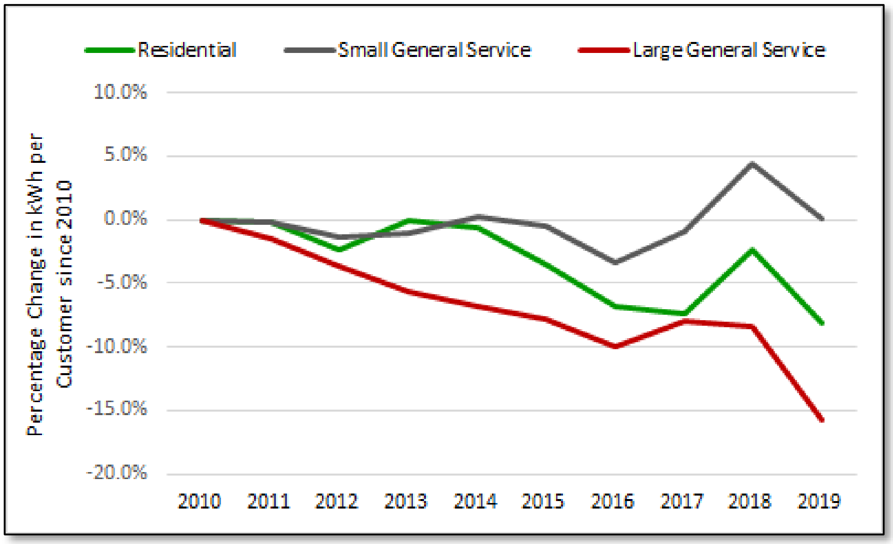
The Figure shows that a significant portion of the Company's residential and commercial distribution revenues are recovered through usage (kWh) and demand (kW) charges. For example, the Figure shows that approximately 60 percent of Residential revenues are recovered through consumption charges.

Q. Has the Company experienced a decline in customer usage that would impact the Company's ability to recover its costs through consumption charges?

A. Yes. The Company has experienced a decline in energy usage per customer over the last 10 years, as shown in Figure 2 (below).

[10] Source: Settlement Agreement in Docket DE 16-384, Attachment 4, p. 1

Figure 2: Percentage Change in kWh per Customer (2010-2019)[11]



The Figure shows use per customer for the Residential and Large General Service ("LGS") rate classes has declined by 8.1 percent and 15.7 percent, respectively, while the use per customer for Small General Service ("SGS") has remained approximately the same.

Q. Please discuss how revenue decoupling supports certain policy objectives?

A. The proposed RDM supports certain policy objectives, such as EE and DER initiatives. Recovery of fixed costs through variable charges creates an inherent financial disincentive for utilities to promote initiatives that reduce customer consumption and has been referenced as a "primary barrier to aggressive utility investment in energy efficiency."[12]

[11] Company's FERC Form 1 Filings, 2010-2019
[12] National Action Plan for Energy Efficiency (2007): Aligning Utility Incentives with Investment in Energy Efficiency, at p. ES-3

The RDM removes this financial disincentive, facilitating policies aimed to encourage EE and DER initiatives.

Q. Has the utility industry recognized the benefits of RDM in achieving policy objectives?

A. Yes. The benefits of revenue decoupling are recognized throughout the U.S. Full revenue decoupling is currently in effect in 22 jurisdictions throughout the U.S., including New Hampshire. In New England, full revenue decoupling is currently in effect for 19 of 26 electric and gas utilities.[13]

Revenue decoupling is recognized by the utility industry as an essential tool in promoting EE and DER initiatives. An ACEEE report states: "For energy efficiency to flourish, the use of decoupling needs to be expanded so that utilities can recover their fixed costs even if sales decline.”[14] The Solar Electric Power Association (“SEPA”), in discussing issues for the Photovoltaic (“PV”) industry, concludes: “Decoupling can eliminate the disincentives that utilities face when customers deploy DR [Demand Response], such as solar PV, by clearly breaking the link between electricity sales and the amount of revenue recovered, while also sharing or eliminating upside and downside risks between the utility and ratepayers.” [15] “[R]emoval of the throughput incentive…can free the utility to

[13] S&P Global Market Intelligence. Data as of October 5, 2020.
[14] ACEEE The Future of the Utility Industry and the Role of Energy Efficiency (June 2014), at p. viii
[15] SEPA Decoupling Utility Profits from Sales: Issues for the Photovoltaic Industry (February 2009), p. 26

pursue cost-effective resources without undermining their shareholder interests."[16]

IV. UES'S PROPOSED REVENUE DECOUPLING MECHANISM

Q. What are the key features of the Company's proposed RDM?

A. There are seven key features of the Company's proposed RDM discussed in this section, including:

1. Type of RDM
2. Revenue Adjustments
3. Applicable Rate Classes
4. Deferred Account
5. Class Allocation
6. Factor Calculation
7. Adjustment Cap

1. Type of RDM

Q. What type of RDM is the Company proposing?

A. The Company's proposed RDM is a full revenue decoupling mechanism. The proposed RDM reconciles monthly variances between actual and authorized RPC for each rate class. As discussed earlier, full revenue decoupling provides greater benefits than partial or limited revenue decoupling.

[16] Id.

Q. What is the primary benefit of the proposed RPC approach?

A. The primary benefit of the proposed RPC approach is consideration for new customer revenues. The Company expects to add new customers and incur incremental costs to serve new customers during the term of the RDM. The incremental costs are related to providing new customers with access to the distribution system and meeting their demand requirements. Under the RPC approach, the Company retains the incremental RPC associated with serving new customers that is used to offset the incremental costs.

By comparison, under a total revenue approach, the Company does not retain incremental revenues to offset the incremental costs, creating an adverse financial impact when adding new customers.

2. <u>Revenue Adjustments</u>

Q. Is the Company proposing annual adjustments to the authorized RPC?

A. Yes. The Company proposes that the authorized RPC be adjusted annually to reflect three estimated step increases on April 1, 2022 of $2.8 million, April 1, 2023 of $3.6 million, and April 1, 2024 of $3.3 million associated with the 2021, 2022 and 2023 capital investments, as discussed in the testimony of Company witnesses Messrs. Christopher Goulding and Daniel Nawazelski.

Q. Why is the Company proposing the annual adjustments?

A. The Company proposes the annual adjustments to align the authorized revenue requirements with the authorized RPC. In other words, as the Company's authorized revenue requirement increases as a result of the step increases, the Company's authorized RPC should similarly increase.

3. <u>Applicable Rate Classes</u>

Q. What rate classes would the proposed RDM apply to?

A. The Company proposes that the RDM be applicable to the Company's Domestic Delivery Service (Schedule D), Domestic Delivery Service (Schedule TOU-D), Regular General Service (Schedule G2), Regular General Service (Schedule G2 kWh meter), Regular General Service (Schedule G2-Quick Recovery Water Heating and Space Heating), and Large General Service (Schedule G1)) customer classes. The Company proposes to exclude the lighting and proposed electric vehicle rate schedules.

4. <u>Deferred Account</u>

Q. Is the Company proposing to establish a deferred account to record variances between actual and authorized RDM?

A. Yes. The Company proposes to establish a deferred account to record monthly variances between actual and authorized RPC. The monthly variances will be calculated by rate class and then recorded in a deferred account with carrying costs at the Prime rate.

The aggregate monthly variances and carrying costs form the basis for the RDA and the calculation of RDAF (surcharge or credit). For example, revenue shortfalls (i.e., actual RPC less than authorized RPC) during the Measurement Period will result in a surcharge to customers while revenue surpluses (i.e., actual

RPC greater than authorized RPC) during the Measurement Period will result in a credit or refund to customers.

Q. What is the proposed process to establish the RDAF?

A. The Company proposes to file with the Commission on June 1 the applicable RDAF. The filing will include an allocation of the RDA to each rate class, and the calculation of the RDAF. The RDA is allocated to each rate class based on the authorized revenues of each rate class in the most recent rate case, including step adjustments. The RDAF will be calculated as a dollar per kWh charge or credit based on the RDA allocated to each rate class divided by the projected kWh sales for each rate class over the RDM Adjustment Period (prospective 12-month period August through July). The RDAF will be charged or credited to customer bills during the RDM Adjustment Period. The RDM process will follow the schedule below.

Dates	Activity
April 1 through March 31	Measure and record monthly in a deferred account the revenue variances between actual and authorized RPC
June 1	File with the Commission the RDAF based on the aggregate monthly revenue variances and monthly carrying costs on the deferred account balances
August 1 through July 31	Apply the RDAF to customer bills

5. <u>Class Allocation</u>

Q. How will the revenue decoupling adjustment be allocated to each rate class?

A. The RDA will be allocated to each rate class (except Lighting and Electric Vehicle rate classes) based on the proportion of authorized revenues in the most recent rate case, including step adjustments.

6. Factor Calculation

Q. How will the RDAF be calculated?

A. The RDAF will be calculated on a dollar per kWh basis for each rate class based on the RDA allocated to each rate class divided by the projected class kWh sales for the RDM Adjustment Period (August through July). The RDAF will be applied to customer bills during the RDM Adjustment Period.

7. Adjustment Cap

Q. Is the Company proposing any adjustment cap?

A. UES proposes to limit the RDA to two and one half (2.5%) percent of total revenues from delivered sales for the most recent twelve-month period, April to March, with revenue for externally supplied customers being adjusted by imputing the Company's default service charges for that period. The cap would be applicable only to revenue shortfalls to help mitigate customer bill impacts. Under-recovered revenues in excess of the adjustment cap would be held in the deferred account with carrying costs and included in the next RDAF filing.

V. ILLUSTRATIVE CALCULATION OF DECOUPLING MECHANISM

Q. How will the Company implement the proposed RDM?

A. As explained above, the proposed RDM process consists of two steps:

In the first step, the Company calculates the monthly variances between actual and authorized RPC for each rate class. The variances are calculated monthly and then aggregated over the twelve-month period April through March (the Measurement Period). The monthly variances are recorded in a deferred account with carrying costs accrued at the Prime rate. The aggregate variances and carrying costs form the basis for the RDA and the calculation of RDAF (surcharge or credit). For example, if the Company experiences a revenue shortfall (actual revenues are less than authorized revenues) during the Measurement Period, the RDM will result in a surcharge for customers. Conversely, if the Company experiences a revenue surplus (actual revenues are greater than authorized revenues) during the Measurement Period, the RDM will result in a credit or refund to customers.

In the second step, the Company files with the Commission on June 1 the applicable RDAF. The filing will include an allocation of the RDA to each rate class, and calculation of the RDAF. The RDA is allocated to each rate classes based on the authorized revenues of each rate class in the most recent rate case, including step adjustments. The RDAF will be calculated as a dollar per kWh charge or credit based on the RDA allocated to each rate class divided by the projected kWh sales for each rate class over the RDM Adjustment Period (twelve-month period August through July). The RDAF will be charged or credited to customer bills during the RDM Adjustment Period.

Q. Please illustrate the first step.

A. In the first step, the Company will calculate monthly variances between actual and authorized RPC for each rate class, as illustrated for the residential rate class in Figure 3 (below).

Figure 3: Monthly Residential Revenue Variance Calculation (Illustrative)[17]

Illustrative Calculation	Actual			Authorized			Variance Over / (Under)	
Variance Over / (Under)	Revenues	Customers	RPC	Revenues	Customers	RPC	RPC	Revenues
April	$ 3,257,856	68,038	$ 47.88	$ 3,241,647	67,032	$ 48.36	$ (0.48)	$ (32,416)
May	3,182,845	69,198	46.00	3,167,010	68,175	46.45	(0.46)	(31,670)
June	3,587,396	69,527	51.60	3,569,548	68,499	52.11	(0.51)	(35,695)
July	4,088,899	69,738	58.63	4,068,556	68,707	59.22	(0.58)	(40,686)
August	4,297,058	69,659	61.69	4,275,679	68,629	62.30	(0.61)	(42,757)
September	3,700,345	70,498	52.49	3,681,936	69,456	53.01	(0.52)	(36,819)
October	3,045,100	69,270	43.96	3,029,950	68,246	44.40	(0.44)	(30,300)
November	3,178,749	68,893	46.14	3,162,934	67,875	46.60	(0.46)	(31,629)
December	3,661,798	68,580	53.39	3,643,580	67,567	53.93	(0.53)	(36,436)
January	3,786,463	68,017	55.67	3,767,625	67,012	56.22	(0.55)	(37,676)
February	3,571,127	67,951	52.55	3,553,360	66,947	53.08	(0.52)	(35,534)
March	3,495,168	68,142	51.29	3,477,779	67,134	51.80	(0.51)	(34,778)
12ME March	$ 42,852,802	827,509		$ 42,639,604	815,280			$ (426,396)

The Figure shows a four-phase process for each month assuming a 1.00 percent reduction in average revenue per customer for the residential sector. In the first phase, the Company calculates the authorized RPC per month by dividing the authorized monthly revenues by authorized monthly number of customers. In the second phase, the Company calculates the actual monthly RPC by dividing the actual revenues by the actual number of customers. In the third phase, the Company calculates the monthly variances between the actual and authorized RPC. In the final phase, the Company calculates the monthly revenue variance by multiplying the RPC variance with the actual number of customers.

The monthly revenue variances will be recorded in a deferred account with carrying costs accrued through the year at the Prime rate, as illustrated for the residential rate class in Figure 4 (below).

[17] The illustrative calculation assumes a 1.00 percent reduction in revenue per customer each month

Figure 4: Deferred Account Balance (Illustrative)[18]

Illustrative Calculation Deferred Account Balance	Deferred Account Starting Balance	Revenue Variance	Carrying Costs Rate	Carrying Costs	Deferred Account Ending Balance
April	$ -	$ (32,416)	0.27%	$ (44)	$ (32,460)
May	(32,460)	$ (31,670)	0.27%	(131)	$ (64,261)
June	(64,261)	$ (35,695)	0.27%	(222)	$ (100,179)
July	(100,179)	$ (40,686)	0.27%	(326)	$ (141,191)
August	(141,191)	$ (42,757)	0.27%	(440)	$ (184,388)
September	(184,388)	$ (36,819)	0.27%	(549)	$ (221,757)
October	(221,757)	$ (30,300)	0.27%	(642)	$ (252,698)
November	(252,698)	$ (31,629)	0.27%	(727)	$ (285,054)
December	(285,054)	$ (36,436)	0.27%	(821)	$ (322,312)
January	(322,312)	$ (37,676)	0.27%	(924)	$ (360,912)
February	(360,912)	$ (35,534)	0.27%	(1,026)	$ (397,471)
March	(397,471)	$ (34,778)	0.27%	(1,124)	$ (433,372)
12ME March		**$ (426,396)**		**$ (6,976)**	**$ (433,372)**

The Figure shows that carrying costs of $6,976 will be accumulated through the year at the assumed Prime Rate. The aggregate monthly variances and carrying costs form the basis for the RDA and the calculation of RDAF surcharge or credit depending on the revenue variances.[19]

Q. Please discuss the second step in calculating the RDM adjustment.

A. In the second step, the Company will file on June 1 the applicable RDAF based on the RDA for the Measurement Period. The filing will include allocation of the RDA to rate classes, and calculation of the RDAF.

The RDA will be allocated to each rate classes based on each class' authorized revenues, including step adjustments, as shown in Figure 5 (below).

[18] The illustrative calculation assumes a Prime Rate of 3.25 percent, or 0.2708 percent monthly
[19] The illustrative calculation shows RDA based on 12 months' ending March balance. However, the Company's proposed RDA filed on June 1 will also include estimated carrying costs through July 31.

Figure 5: Deferred Account Balance (Illustrative)[20]

Illustrative Revenue Decoupling Adjustment Allocation		Authorized Revenues ($)	Authorized Revenues (%)		Allocated RDA ($)
Residential (Domestic)	$	42,639,604	60.13%	$	(260,603)
Regular General Service (G2)		19,097,967	26.93%		(116,722)
Regular General Service (G2 - kWh Meter)		100,190	0.14%		(612)
Regular General Service (G2 - QRWH)		199,187	0.28%		(1,217)
Large General Service (G1)		8,871,050	12.51%		(54,218)
Total	$	70,907,996	100.00%	$	(433,372)

The Figure shows that the residential class revenues are 60.13 percent of total Company revenues. Accordingly, the deferred account balance allocated to the residential class is $260,603.

The allocated RDA forms the basis for the calculation of RDAF for each rate class, as shown in Figure 6 (below).

Figure 6: Calculation of RDAF (Illustrative)

Illustrative Revenue Decoupling Adjustment Factor Calculation		Charge/ (Refund) ($)	Illustrative Projected Sales (kWh)		Charge/ (Refund) ($/kWh)
Residential (Domestic)	$	260,603	516,000,000	$	0.00051
Regular General Service (G2)		116,722	312,500,000		0.00037
Regular General Service (G2 - kWh Meter)		612	450,000		0.00136
Regular General Service (G2 - QRWH)		1,217	4,500,000		0.00027
Large General Service (G1)		54,218	320,000,000		0.00017
Total	$	433,372	1,153,450,000		

The Figure shows that the RDAF for the Residential class will be $0.00051 per kWh. The adjustment factor would be implemented on customer bills during the August through July RDM Adjustment Period.

Q. Please describe how the RDAF will appear on customer bills.

[20] The illustrative deferred account balance assumes that only the Residential class experienced a revenue change.

A. For billing purposes, the Company plans to add the RDAF to the Distribution Charge component.

Q. Is the proposed RDM subject to reconciliation?

A. Yes. As described in Section 7.0 of the proposed tariff, the RDM is subject to reconciliation. Specifically, the actual revenues received by the Company through application of the RDAF to customer bills is reconciled to the RDM adjustment amount.

Q. Does this conclude your direct testimony?

A. Yes, it does.

[THIS PAGE INTENTIONALLY LEFT BLANK]

Summary

Tim Lyons is a partner with ScottMadden with more than 30 years of experience in the energy industry. Tim has held senior positions at several gas utilities and energy consulting firms. His experience includes rate and regulatory support, sales and marketing, customer service and strategy development. Prior to joining ScottMadden, Tim was Vice President of Sales and Marketing for Vermont Gas. He has also served as Vice President of Marketing and Regulatory Affairs for Providence Gas Company, Director of Rates at Boston Gas Company, and Project Director at Quantec, LLC, an energy consulting firm.

Tim has sponsored testimony before 20 state regulatory commissions. Tim holds a B.A. from St. Anselm College, an M.A. in Economics from The Pennsylvania State University, and an M.B.A. from Babson College.

Areas of Specialization

- Regulation and Rates
- Retail Energy
- Utilities
- Natural Gas

Capabilities

- Regulatory Strategy and Rate Case Support
- Strategic and Business Planning
- Capital Project Planning
- Process Improvements

Articles and Speeches

- "Country Strong: Vermont Gas shares its comprehensive effort to expand natural gas service into rural communities." ***American Gas Association***, June 2011 (with Don Gilbert).
- "Talking Safety With Vermont Gas." ***American Gas Association***, February 2009 (with Dave Attig).
- "Consumers Say 'Act Now' To Stabilize Prices." ***Power & Gas Marketing***, September/ October 2001 (with Jim DeMetro and Gerry Yurkevicz).
- "Rate Reclassification: Who Buys What and When." ***Public Utilities Fortnightly***, October 15, 1991 (with John Martin).

Sponsor	Date	Docket No.	Subject
Regulatory Commission of Alaska			
ENSTAR Natural Gas Company	06/16	Docket No. U-16-066	Adopted testimony and sponsored Lead/Lag study for a general rate case proceeding.
Arkansas Public Service Commission			
Liberty Utilities (Pine Bluff Water)	10/18	Docket No. 18-027-U	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding.
California Public Utilities Commission			
Southwest Gas Corporation (Southern California, Northern California and South Lake Tahoe jurisdictions)	8/19	Docket No. A.19-08-015	Sponsored testimony on behalf of three separate rate jurisdictions related to: revenue requirements, lead-lag/ cash working capital, and class cost of service, rate design and bill impact analysis for a general rate case proceeding.
Connecticut Public Utilities Regulatory Authority			
Yankee Gas Company	07/14	Docket No. 13-06-02	Sponsored report and testimony supporting the review and evaluation of gas expansion policies, procedures and analysis.
Illinois Commerce Commission			
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. 16-0401	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes and a decoupling mechanism.
Iowa Utilities Board			
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. RPU-2016-0003	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes.
Kansas Corporation Commission			
The Empire District Electric Company	12/18	Docket No. 19-EPDE-223-RTS	Sponsored testimony supporting cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Maine Public Utilities Commission			
Northern Utilities, Inc. d/b/a Unitil	06/19	Docket No. 2019-00092	Sponsored testimony supporting a proposed capital investment cost recovery mechanism.
Northern Utilities, Inc. d/b/a Unitil	06/15	Docket No. 2015-00146	Sponsored testimony supporting the proposed gas expansion program, including a zone area surcharge.
Maryland Public Service Commission			
Sandpiper Energy, a Chesapeake Utilities company	12/15	Case No. 9410	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new residential and commercial classes.
Massachusetts Department of Public Utilities			
Liberty Utilities (New England Gas Company)	07/18	Docket No. DPU 18-68	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2018/2019 through 2022/2023.

Sponsor	Date	Docket No.	Subject
Liberty Utilities (New England Gas Company)	07/16	Docket No. DPU 16-109	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2016/2017 through 2020/2021.
Boston Gas	10/93	Docket No. DPU 92-230	Sponsored testimony describing the Company's position regarding rate treatment of vehicular natural gas investments and expenses.
Boston Gas	03/90	Docket No. DPU 90-55	Sponsored testimony supporting the weather and other cost of service adjustments, rate design and customer bill impact studies for a general rate case proceeding.
Boston Gas	03/88	Docket No. DPU 88-67-II	Sponsored testimony supporting the rate reclassification of commercial and industrial customers for a rate design proceeding.
Michigan Public Service Commission			
Lansing Board of Water & Light and Michigan State University	04/20	Docket No. U-20650	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Lansing Board of Water & Light and Michigan State University	04/19	Docket No. U-20322	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Midland Cogeneration Ventures, LLC	09/18	Docket No. U-18010	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Missouri Public Service Commission			
Spire Missouri, Inc.	12/20	Docket No. GR-2021-0108	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
The Empire District Electric Company	08/19	Docket No. ER-2019-0374	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding. The testimony also included proposals for a weather normalization mechanism.
Liberty Utilities (Midstates Natural Gas)	09/17	Docket No. GR-2018-0013	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding. The testimony also included proposals for a revenue decoupling/ weather normalization mechanism as well as tracker accounts for certain O&M expenses and capital costs.
Missouri Gas Energy	04/17	Docket No. GR-2017-0216	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
Laclede Gas Company	04/17	Docket No. GR-2017-0215	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
New Hampshire Public Utilities Commission			

Sponsor	Date	Docket No.	Subject
Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities	11/17	Docket No. DG 17-198	Sponsored testimony supporting a levelized cost analysis for approval of firm supply and transportation agreements.
Liberty Utilities d/b/a Granite State Electric Company	04/16	Docket No. DE 16-383	Adopted testimony and sponsored Lead/Lag study for a general rate case proceeding.
Nevada Public Utilities Commission			
Southwest Gas Corporation	02/20	Docket No. 20-02023	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
New Jersey Board of Public Utilities			
South Jersey Gas Company	03/20	Docket No. GR20030243	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Elizabethtown Gas Company	04/19	Docket No. GR19040486	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas Company	08/16	Docket No. GR16090826	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Corporation Commission of Oklahoma			
The Empire District Electric Company	03/19	Cause No. PUD 201800133	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
The Empire District Electric Company	04/17	Cause No. PUD 201600468	Adopted direct testimony and sponsored rebuttal testimony supporting the revenue requirements for a general rate case proceeding. The testimony included proposals for alternative ratemaking mechanisms.
Rhode Island Public Utilities Commission			
Providence Gas Company	08/01 09/00 08/96	Docket No. 1673	Sponsored testimony supporting the changes in cost of gas adjustment factor related to projected under-recovery of gas costs; Filed testimony and witness for pilot hedging program to mitigate price risks to customers; Filed testimony and witness for changes in cost of gas adjustment factor related to extension of rate plan.
Providence Gas Company	08/00	Docket No. 2581	Sponsored testimony supporting the extension of a rate plan that began in 1997 and included certain modifications, including a weather normalization clause.
Providence Gas Company	03/00	Docket No. 3100	Sponsored testimony supporting the de-tariff and deregulation of appliance repair service, enabling the Company to have needed pricing flexibility.
Providence Gas Company	06/97	Docket No. 2581	Sponsored testimony supporting a rate plan that fixed all billing rates for three-year period; included funding for critical infrastructure investments in accelerated replacement of mains and services, digitized records system, and economic development projects.

Sponsor	Date	Docket No.	Subject
Providence Gas Company	04/97	Docket No. 2552	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for commercial and industrial customers, including redesign of cost of gas adjustment clause, for a rate design proceeding.
Providence Gas Company	02/96	Docket No. 2374	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for largest commercial and industrial customers for a rate design proceeding.
Providence Gas Company	01/96	Docket No. 2076	Sponsored testimony supporting the rate reclassification of customers into new rate classes, rate design (including introduction of demand charges), and customer bill impact studies for a rate design proceeding.
Providence Gas Company	11/92	Docket No. 2025	Sponsored testimony supporting the Integrated Resource Plan filing, including a performance-based incentive mechanism.
Railroad Commission of Texas			
Texas Gas Service Company – Central Texas and Gulf Coast Service Areas	12/19	GUD No. 10928	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – Beaumont/ East Texas Division	11/19	GUD No. 10920	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Borger/ Skellytown Service Area	08/18	GUD No. 10766	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – North Texas Service Area	06/18	GUD No. 10739	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – South Texas Division	11/17	GUD No. 10669	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Rio Grande Valley Service Area	06/17	GUD No. 10656	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Atmos Pipeline – Texas	01/17	GUD No. 10580	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – Texas Gulf Division	11/16	GUD No. 10567	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Public Utility Commission of Texas			
CenterPoint Energy Houston Electric, LLC	04/19	Docket No. 49421	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Vermont Public Utilities Commission			
Vermont Gas Systems	12/12	Docket No. 7970	Sponsored testimony describing the market served by $90 million natural gas expansion project to Addison County, VT. Also described the terms and economic benefits of a special contract with International Paper.

Sponsor	Date	Docket No.	Subject
Vermont Gas Systems	02/11	Docket No. 7712	Sponsored testimony supporting the market evaluation and analysis for a system expansion and reliability regulatory fund.
Virginia State Corporation Commission			
American Electric Power - Appalachian Power Company	3/20	Case No. PUR-2020-00015	Sponsored testimony supporting the Lead/Lag study for the 2020 triennial review of base rates, terms and conditions.

REVENUE DECOUPLING ADJUSTMENT CLAUSE

1.0 PURPOSE

The purpose of the Revenue Decoupling Adjustment Clause ("RDAC") is to establish procedures that allow the Company to adjust, on an annual basis, rates for distribution service that reconcile Actual Base Revenues per Customer with Authorized Base Revenues per Customer.

2.0 EFFECTIVE DATE

The Revenue Decoupling Adjustment Factor ("RDAF") shall be effective on the first day of the Adjustment Period, as defined in Section 4.0.

3.0 APPLICABILITY

The RDAF shall apply to the Company's Domestic Delivery Service (Schedule D), Domestic Delivery Service (Schedule TOU-D) and General Delivery Service (Schedule G), as determined in accordance with the provisions of this Tariff.

4.0 DEFINITIONS

The following definitions shall apply throughout the Tariff:

1. Actual Base Revenues is the revenue collected for a Customer Class through the Company's customer charge and distribution charges. This excludes revenues collected through the RDAF.
2. Actual Number of Customers is the number of customers for the applicable customer class. Actual Number of Customers shall be based on the monthly equivalent bills for a customer class.
3. Actual Base Revenues per Customer is Actual Base Revenues divided by the Actual Number of Customers for a Customer Class.
4. Adjustment Period is the 12-month period for which the RDAF will be applied for each applicable customer class. The first Adjustment Period shall be the twelve-month period from August 1, 2023 to July 31, 2024. Each subsequent Adjustment Period shall be the twelve months August 1 through July 31.
5. Authorized Base Revenues is the base revenues for a Customer Class as authorized by the Commission in the Company's most recent base rate case or other proceedings that result in an adjustment to base rates, or as adjusted by Commission order. This includes revenues authorized to be recovered through the Company's customer charge and distribution

charges. This also includes any step revenue increases authorized by the Commission, but excludes revenues authorized to be recovered from the RDAF.

6. Authorized Base Revenues per Customer is the Authorized Base Revenues divided by the Authorized Number of Customers for a customer class.
7. Authorized Number of Customers is the number of customers in the test year for the applicable Customer Class as used in the rate design in the Company's most recent base rate case or as adjusted by Commission order.
8. Customer Class is the group of customers for purposes of calculating the Revenue Decoupling Adjustment amounts defined as follows: Domestic Delivery Service (Schedule D), Domestic Delivery Service (Schedule TOU-D), Regular General Service (Schedule G2), Regular General Service (Schedule G2 kWh meter), Regular General Service (Schedule G2 Quick Recovery Water Heating and Space Heating), and Large General Service (Schedule G1).
9. Measurement Period is the 12-month period in which the Company will measure variances between actual base revenues per customer and authorized base revenues per customer for each customer class. The first Measurement Period shall be the twelve-month period from April 1, 2022 to March 31, 2023. Each subsequent Measurement Period shall be the twelve months April 1 through March 31.
10. Revenue Decoupling Adjustment ("RDA") is the cumulative monthly revenue variances, carrying costs and reconciliation amount for the Measurement Period. The RDA forms the basis for RDAF.

5.0 CALCULATION OF REVENUE DECOUPLING ADJUSTMENT FACTOR

i. Description of RDAF Calculation

For each month within the Measurement Period, the Company shall calculate the variance between Actual Revenue per Customer and Authorized Revenue per Customer, for each Customer Class as defined in Section 4.0. The revenue per customer variance will be multiplied by the Actual Number of Customers per class, to determine the monthly Customer Class revenue variance. The revenue variance will be recorded in a deferral account with carrying costs accrued monthly at Prime rate with said Prime rate to be fixed on a quarterly basis and to be established as reported in THE WALL STREET JOURNAL on the first business day of the month preceding the calendar quarter. If more than one interest rate is reported, the average of the reported rates shall be used. On June 1 following the end of each Measurement Period, the Company will file for implementation of the RDAF, starting the first day of the Adjustment Period. The RDA at the end of Measurement Period will form the basis for the RDAF calculation. The RDA, including reconciliation amount and carrying costs, will be allocated to each customer class based upon the percentage of each class' Authorized Base Revenue, including step adjustments. The resulting class RDA will be divided by the class's projected sales for the adjustment period to determine the RDAF applicable to the given customer class.

ii. RDAF Calculation

1. Monthly Revenue Variance (MRV)

$$MRV_i^{CC} = \left(ARPC_i^{CC} - AURPC_i^{CC}\right) x\ ACUST_i^{CC}$$

Where:

$ACUST_i^{CC}$: Actual number of customers for month i for applicable Customer Class.

$ARPC_i^{CC}$: Actual Base Revenue Per Customer for month i for applicable Customer Class, derived as:

$$ARPC_i^{CC} = \frac{Actual\ Month\ i\ Revenue\ for\ Customer\ Class}{Actual\ Month\ i\ Bills\ for\ Customer\ Class}$$

$AURPC_i^{CG}$: Authorized Base Revenue Per Customer for month i for applicable Customer Class, derived as:

$$AURPC_i^{CC} = \frac{Authorized\ Month\ i\ Revenue\ for\ Customer\ Class}{Authorized\ Month\ i\ Bills\ for\ Customer\ Class}$$

CC: The six Customer Classes as defined in Section 4.0.

i: The twelve Months of the Measurement Period (April through March)

2. Revenue Decoupling Adjustment (RDA)

$$RDA\ = [\textstyle\sum_{CC=1}^{6}[\sum_{i=1}^{12} MRV_i^{CC} + CarryingCosts_i^{CC}\ ]] + REC_P$$

Where:

$CarryingCosts_i^{CC}$: Carrying Costs on the deferral account balance calculated at Prime rate for month i for applicable Customer Class.

REC_P: RDAC Reconciliation Balance from prior period p as defined in Section 7.0.

3. RDA Allocation, subject to Adjustment Cap

$IF: RDA < 0$
$AND\ IF: |RDA| > RDC$

$$THEN: RDA^{CC} = RDC \times \frac{AURV^{CC}}{\sum_{CC=1}^{CC=6}[AURV^{CC}]}$$

$$AND: REC_C = RDA - RDC$$

$$OTHERWISE: RDA^{CC} = RDA \times \frac{AURV^{CC}}{\sum_{CC=1}^{CC=6}[AURV^{CC}]}$$

Where:

$|RDA|$: Absolute Value of RDA

$AURV^{CC}$: Authorized Base Revenues for Customer Class

RDC: The Revenue Decoupling Cap that equals two and one half (2.5%) percent of total revenues from delivered sales for the most recent twelve-month period, April to March, as defined in Section 8.0 for the Adjustment Period. This cap is applicable to under recoveries only; over recoveries shall be credited in full.

REC_C: RDAC Reconciliation Balance for current period as defined in Section 7.0.

4. RDAF Calculation

$$RDAF^{CC} = -1 \times \frac{RDA^{CC}}{FS^{CC}}$$

Where:

FS^{CC}: The forecasted kWh Sales for the Adjustment Period for the applicable customer class

6.0 Application of the RDAF to Customer Bills

The RDAF ($ per kWh) shall be truncated at the nearest one one-thousandths of a cent per kWh. The RDAF will be applied to the monthly billed sales for each customer during the applicable Adjustment Period.

7.0 RDAC Reconciliation

The deferred balance shall contain the accumulated difference between the authorized RDA for the Adjustment Period determined in accordance with Section 4.0, and actual revenues received by the Company through application of the RDAF to customer bills in the Adjustment Period. Carrying costs shall be calculated on the average monthly balance of the deferred balance using the Prime rate.

8.0 Revenue Decoupling Adjustment Cap

The RDA for the Adjustment Period (determined in accordance with Section 5.0) may not exceed two and one half (2.5%) percent of total revenues from delivered sales for the most recent twelve-month period, April to March, with revenue for externally supplied customers being adjusted by imputing the Company's default service charges for that period. Total revenue shall include amounts that the Company has billed the Customer Classes as defined in Section 4.0 through applicable charges for distribution service, external delivery charge, stranded cost charge, storm recovery adjustment charge, system benefits charge, and any and all related adjustment factors. This cap is applicable to under recoveries only; over recoveries shall be credited in full. To the extent that the application of the RDA cap results in a RDA that is less than that calculated in accordance with Section 5.0, the difference shall be deferred and included in the RDAC Reconciliation for recovery in the subsequent Adjustment Period. Carrying costs shall be calculated on the average monthly balance using the Prime rate.

9.0 Information to be Filed with the Commission

Information pertaining to the RDAC will be filed annually on June 1 with the Commission consistent with the filing requirements of all costs and revenue information included in the Tariff. Such information shall include:

1. Calculation of monthly revenue variances for each Customer Class.

2. Determination of Revenue Decoupling Adjustment for the upcoming Adjustment Period.
3. Allocation of Revenue Decoupling Adjustment to each Customer Class.
4. Calculation of the Revenue Decoupling Adjustment Factors for each Customer Class, to be utilized in the upcoming Adjustment Period. If distribution rates change during the Measurement Period, the monthly revenue per customer for the remaining months of the Measurement Period will be revised and filed with the Commission.

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY

OF

JENNIFER E. NELSON

EXHIBIT JEN-1

New Hampshire Public Utilities Commission

Docket No. DE 21-030

TABLE OF CONTENTS

LIST OF EXHIBITS

I. INTRODUCTION & PURPOSE

Q. Please state your name, affiliation, and business address.

A. My name is Jennifer E. Nelson. I am an Assistant Vice President at Concentric Energy Advisors. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts, 01742.

Q. On whose behalf are you submitting this testimony?

A. I am submitting this direct testimony ("Direct Testimony") before the New Hampshire Public Utilities Commission ("Commission") on behalf of Unitil Energy Systems, Inc. ("UES" or the "Company").

Q. Please describe your professional experience and educational background.

A. I have worked in the energy industry for nearly thirteen years, having served as a consultant and energy/regulatory economist for state government agencies. Since 2013, I have provided consulting services to utility and regulated energy clients on a range of financial and economic issues including rate case support (*e.g.*, cost of capital and integrated resource planning) and policy and strategy issues (*e.g.*, alternative ratemaking and natural gas distribution expansion). Prior to consulting, I was a staff economist at the Massachusetts Department of Public Utilities, where I worked on regulatory filings related to energy efficiency, renewable power contracts, smart grid and electric grid modernization, and retail choice; prior to that, I was a petroleum economist at the State of Alaska Department of Revenue.

I hold a Bachelor's degree in Business Economics from Bentley College (now Bentley University) and a Master's degree in Resource and Applied Economics from the University of Alaska.

A summary of my professional and educational background, including a list of my testimony filed before regulatory commissions, is included as Exhibit JEN-2.

Q. Have you previously submitted testimony to the New Hampshire Public Utilities Commission?

A. No, I have not. However, I have previously filed testimony before regulatory commissions in Arkansas, Kentucky, Maine, New Mexico, Texas, and West Virginia. During my time as a consultant, I have supported the development of expert witness testimony and analyses regarding the Return on Equity ("ROE")[1] and capital structure for regulated utilities in more than 100 proceedings filed before numerous U.S. state regulatory commissions and the Federal Energy Regulatory Commission.

Q. What is the purpose of your Direct Testimony?

A. The purpose of my Direct Testimony is to present evidence and provide the Commission with a recommendation regarding UES's ROE and to assess the reasonableness of the Company's requested capital structure. My analyses and conclusions are supported by the data presented in Exhibit JEN-3 through Exhibit JEN-10.

---

1 Throughout my testimony, I interchangeably use the terms "ROE" and "Cost of Equity."

Q. Were your testimony and exhibits prepared by you or under your direction?

A. Yes.

II. SUMMARY AND OVERVIEW OF TESTIMONY

Q. What are your conclusions regarding the appropriate Cost of Equity and capital structure for UES?

A. My analyses indicate that UES's Cost of Equity currently is in the range of 9.90 percent to 10.50 percent. Based on the quantitative and qualitative analyses discussed throughout my Direct Testimony, and considering UES's risk profile and the current volatile capital market environment, I conclude that an ROE of 10.20 percent is reasonable and appropriate. Further, I conclude that the Company's requested capital structure consisting of 52.91 percent common equity, 0.10 percent preferred equity, 46.99 percent long-term debt, and 0.00 percent short-term debt is reasonable and should be used for ratemaking purposes.

Q. Please provide a brief overview of the analyses that led to your ROE recommendation.

A. The Cost of Equity, which is the return required by equity investors to assume the risks of ownership, is a market-based concept. Because it is not directly observable, the Cost of Equity is estimated based on financial models that rely on market data. Since all financial models are subject to various assumptions and constraints, equity analysts and investors tend to use multiple methods to develop their return requirements. As such, I relied on three widely accepted approaches to develop my ROE determination: (1) the constant growth and quarterly forms of the Discounted Cash Flow ("DCF") model; (2) the traditional and empirical forms of the Capital Asset Pricing Model ("CAPM"); and (3) the Bond Yield Plus Risk Premium approach. The results of those analytical approaches are summarized in Table 1 below.

Table 1: Summary of Results[2]

Constant Growth DCF	**Low**	**Mean**	**High**
30-Day Average	8.45%	9.20%	9.83%
90-Day Average	8.44%	9.06%	9.75%
180-Day Average	8.48%	9.09%	9.84%
Quarterly Growth DCF	**Low**	**Mean**	**High**
30-Day Average	8.55%	9.29%	9.99%
90-Day Average	8.52%	9.14%	9.91%
180-Day Average	8.55%	9.21%	9.99%
***Value Line*-based CAPM**		**Current 30-Year Treasury Yield (1.97%)**	**Projected 30-Year Treasury Yield (2.72%)**
Proxy Group Average		12.82%	12.91%
Proxy Group Median		12.48%	12.59%
***Value Line*-based Empirical CAPM**		**Current 30-Year Treasury Yield (1.97%)**	**Projected 30-Year Treasury Yield (2.72%)**
Proxy Group Average		13.20%	13.27%
Proxy Group Median		12.95%	13.03%
Bond Yield Plus Risk Premium			
Current 30-Year Treasury Yield (1.97%)		9.89%	
Projected 30-Year Treasury Yield (2.72%)		9.80%	

[2] *See*, Exhibits JEN-3, JEN-4, JEN-6, JEN-7. DCF model results represent the average of the mean and median proxy group results.

In addition to the methods noted above, I considered the Company's small size relative to the proxy group and its proposed revenue decoupling mechanism in my recommendation. I also considered the currently unstable capital market and macroeconomic environment in which utilities such as UES operate. Although those factors are relevant to investors, their effect on the Company's Cost of Equity cannot be directly quantified. Therefore, rather than make explicit adjustments to my ROE estimates in connection with those factors, I considered them in determining where the Company's Cost of Equity falls within the range of analytical results.

Q. How did you determine your recommended range from the methods and results summarized above?

A. As noted earlier, the Cost of Equity is not directly observable and must be estimated based on both quantitative and qualitative information. As my Direct Testimony explains, no single model is more reliable than all others under all market conditions. All models used to estimate the Cost of Equity are subject to certain assumptions, which may become more or less relevant as market conditions change. Each model's results must be assessed in the context of current and expected capital market conditions, as well as relative to appropriate benchmarks. Consequently, many finance texts recommend using multiple approaches to estimate the Cost of Equity.[3] Because estimating the Cost of Equity is an approximation of investor behavior and cannot be precisely quantified, analysts and investors gather and evaluate relevant data from a wide variety of sources

---

3 *See, for example,* Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed., 1994, at 341, and Tom Copeland, Tim Koller and Jack Murrin, Valuation: Measuring and Managing the Value of Companies, 3rd Ed., 2000, at 214.

and rely on multiple analytical approaches. The use of various financial models provides different perspectives on investor return requirements, which enables a more robust and comprehensive assessment of the Cost of Equity.

Simply, each model has its strengths and weaknesses, and it is important to recognize those differences when estimating the Cost of Equity. For example, the Constant Growth DCF model requires constant assumptions, inputs, and results in perpetuity, while Risk Premium-based methods provide the ability to reflect investors' views of risk, future market returns, and the relationship between interest rates and the Cost of Equity. Other Risk Premium approaches (*e.g.*, the Bond Yield Plus Risk Premium approach) reflect the well-documented finding that the Cost of Equity does not move in lockstep with interest rates.

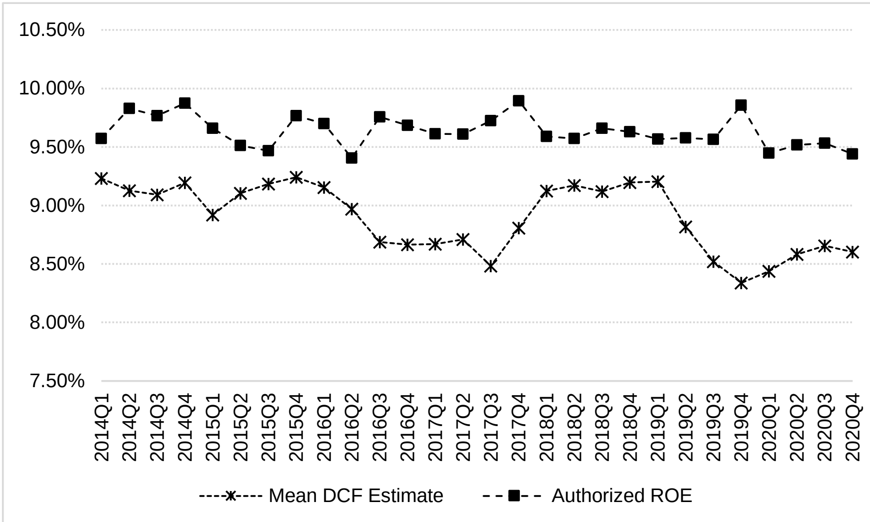
My recommendation therefore recognizes that estimating the Cost of Equity is not an entirely mathematical exercise. It relies on both quantitative and qualitative data and analyses, all of which are used to inform the judgment that necessarily must be applied in determining the Cost of Equity for a particular company at a particular time. As such, I considered my analytical results in the context of Company-specific factors and current capital market conditions. The wide range of analytical results summarized in Table 1 above reflect the considerable uncertainty surrounding the scope and duration of the current economic and capital market associated with the COVID-19 pandemic. In developing my recommendation, I considered the quantitative results produced by each model and their comparability to returns available to other similarly-situated electric utilities, as well as each model's consistency with, and reflection of, the current capital market environment.

As discussed below, the DCF model may not be producing reasonable results for the proxy group in the current market environment. Because Risk Premium-based methods more directly reflect increased risk associated with market volatility and uncertainty, it is reasonable to give more weight to Risk premium-based estimates than to the DCF-based estimates. Nonetheless, even if each of the analytical results shown in Table 1 are given equal weight – including the low and high estimates – the average is 10.29 percent. Although current market conditions suggest the investor-required ROE now falls toward the higher end of my recommended range, I conclude an ROE of 10.20 percent, within a range of 9.90 percent to 10.50 percent, is conservative and reasonably reflects the market uncertainty reflected in methods on which investors rely.

Q. Why do you believe the Constant Growth DCF model does not provide an accurate estimate of UES's Return on Equity?

A. As discussed below, the period over which my analyses were performed included market data that were inconsistent with that model's fundamental assumptions and produced results that are not consistent with current capital market conditions. Since 2014, the DCF model has produced results (*i.e.*, mean results) consistently and meaningfully below authorized returns (*see*, Chart 1, below). That data suggests state regulatory commissions have recognized the DCF model's mean results are not necessarily reliable estimates of the Cost of Equity, and that other methods should be given meaningful weight in determining the ROE.

Chart 1: Mean DCF Results vs. Authorized ROE Over Time[4]



Q. Have other state regulatory commissions declined to rely on the DCF model results?

A. Yes. For example, in its June 2018 *Order Accepting Stipulation* in which it authorized a 9.90 percent ROE for Duke Energy Carolinas, the North Carolina Utilities Commission noted it "carefully evaluated the DCF analysis recommendations" of the ROE witnesses (which ranged from 8.45 percent to 8.80 percent) and determined that "all of these DCF analyses in the current market produce unrealistically low results."[5]

---

4 DCF results are based on quarterly average stock prices and the average projected Earnings Per Share growth rate from *Value Line*, Zacks, and First Call for all companies classified as electric utilities by *Value Line*. Authorized ROEs are quarterly averages. Source: S&P Global Market Intelligence.

5 State of North Carolina Utilities Commission, Docket No. E-7, Sub 1146, In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, June 22, 2018, at 62.

Q. Are there aspects of the DCF model that may explain why the Commission should not rely principally on it when determining the Cost of Equity?

A. Yes, the DCF model's underlying structure and assumptions are not compatible with the recent capital market and economic environment. In particular, the dividend yield component and the expected growth rate component of the DCF model are theoretically and fundamentally linked. In one sense, relatively low dividend yields should be associated with relatively high growth rates. That is, relatively low dividend yields are the result of relatively high stock prices which, in turn, should be associated with relatively high growth rates. If those relationships do not hold, the model's results should be viewed with some caution.

In recent years, the Price/Earnings ratio for the proxy group has been above its long-term average (*see*, Chart 2 below), indicating higher valuations that produce lower dividend yields (*see*, Chart 3 below).

Chart 2: Proxy Group Price/Earnings Ratio (1997-2021)[6]

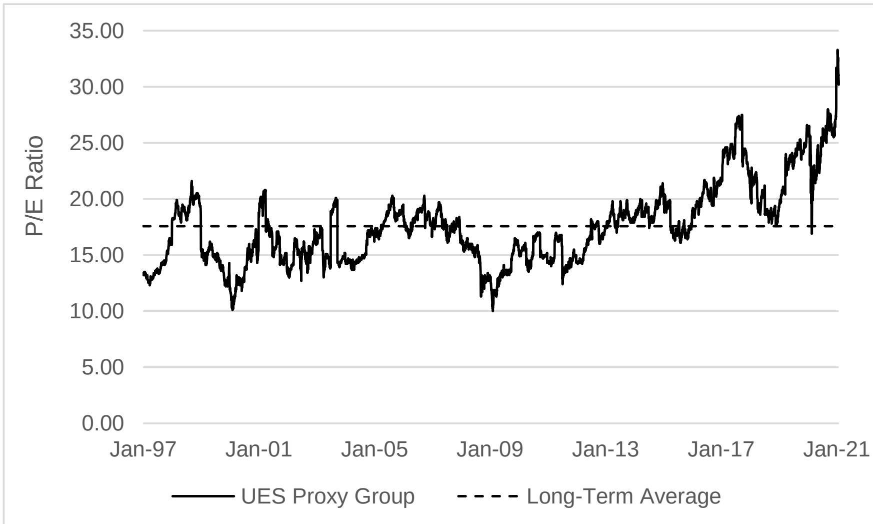
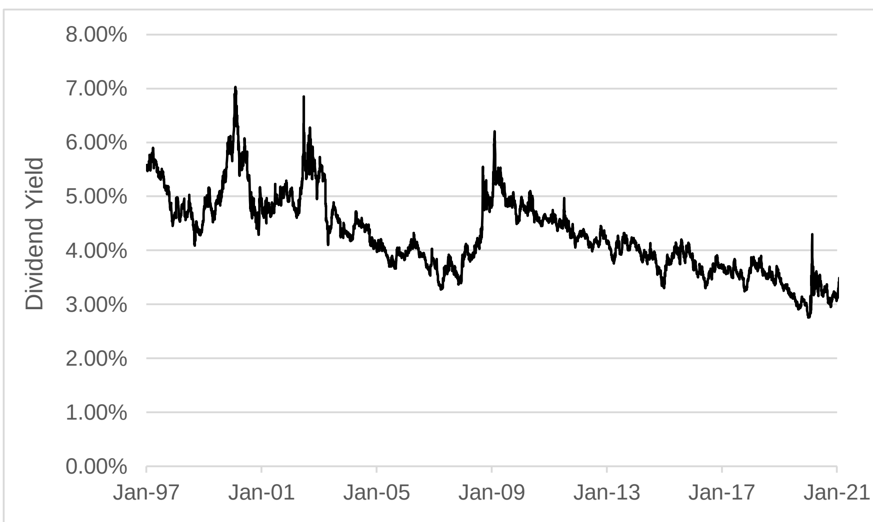


Chart 3: Proxy Group Dividend Yield (1997-2021)[7]



---

6 Source: S&P Global Market Intelligence. Proxy group calculated as an index.
7 Source: S&P Global Market Intelligence. Proxy group calculated as an index.

However, the average proxy group growth rate applied in my DCF analyses (5.39 percent[8]) is below the arithmetic average capital appreciation[9] rate (6.28 percent) for the proxy group between the end of 1996 and the end of 2020.[10] From that perspective, the fundamental relationship between the dividend yield and growth rates under the DCF model may not currently hold for the proxy group. Stated differently, relatively high stock prices (and therefore relatively low dividend yields) and relatively low growth rates have combined to produce DCF results that are inconsistent with the fundamental theory underlying the model.

Moreover, the DCF model assumes investors use its fundamental structure to find the "intrinsic" value of stock, that is, the price they are willing to pay.[11] In practice, investors also consider relative valuation multiples – Price/Earnings, Market/Book, Enterprise Value/EBITDA[12] – in their buying and selling decisions. They do so because no single financial model produces the most accurate measure of fundamental value, or the most reliable estimate of the Cost of Equity, at all times.

Whereas the Constant Growth and Quarterly Growth DCF models assume existing capital market conditions will remain constant, Risk Premium based methods more directly reflect the volatile capital market environment described in Section III.B. below. Because the DCF model's underlying fundamental relationship may not currently hold

---

8 *See* Exhibit JEN-3 and Exhibit JEN-4.
9 Under the Constant Growth DCF model's assumptions, the growth rate equals the rate of capital appreciation. *See, e.g.,* Roger A. Morin, Ph.D., New Regulatory Finance, at 256 (2006).
10 Source: S&P Global Market Intelligence. Proxy group calculated as an index.
11 *See*, Equations [1] and [2].
12 Earnings Before Interest, Taxes, Depreciation, and Amortization.

for the proxy group, I conclude it should be given less weight than other methods in determining the Company's ROE. Regardless of the method employed, however, an authorized ROE that is well below returns authorized for other utilities: (1) runs counter to the *Hope*[13] and *Bluefield*[14] "comparable risk" standard; and (2) would make it difficult for the Company to compete for capital at reasonable terms, placing it at a competitive disadvantage.

Q. Is it your view that the DCF model should be given no weight in determining the company's Cost of Equity?

A. No, it is not. It is my view, however, that we should carefully consider the range of results the model produces in arriving at ROE recommendations. Considering the potential disconnect in the fundamental relationship between the current proxy group dividend yield and growth rates, if the Commission gives weight to the DCF model, it is my opinion that more weight should be given to the upper end of the DCF results.

Q. How is the remainder of your Direct Testimony organized?

A. The remainder of my Direct Testimony is organized as follows:

- <u>Section III</u> – Provides a summary of issues and regulatory guidelines regarding Cost of Equity estimation in regulatory proceedings, discusses the current capital market conditions and their effect on UES's Cost of Equity, explains my selection of the

---

13 *See, Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).
14 *See, Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679, 692-93 (1923); and *Federal Power Commission v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944).

proxy group used to develop my analytical results, and describes my analyses on which my ROE determination is based;

- Section IV – Discusses the specific business risks that have a direct bearing on UES's Cost of Equity;
- Section V – Assesses the Company's requested capital structure; and
- Section VI – Summarizes my conclusions and recommendations.

III. COST OF EQUITY ESTIMATION

A. Regulatory Guidelines and Financial Considerations

Q. Before addressing the specific aspects of this proceeding, please provide a general overview of the issues surrounding the Cost of Equity in regulatory proceedings.

A. In general terms, the Cost of Equity is the return that investors require to make an equity investment in a firm. Investors will provide funds to a firm only if the return they *expect* is equal to, or greater than, the return they *require* to accept the risk of providing funds to the firm. From the firm's perspective, that required return, whether it is provided to debt or equity investors, has a cost. Individually, we speak of the "Cost of Debt" and the "Cost of Equity" as measures of those costs; together, they are referred to as the "Cost of Capital."

The Cost of Capital (including the costs of both debt and equity) is based on the economic principle of "opportunity costs." Investing in any asset, whether debt or equity securities, represents a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least equal to the return expected on alternative, comparable risk investment opportunities. Because investments with similar risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk. In that important respect, the returns required by debt and equity investors represent a cost to the Company.

Although both debt and equity have required costs, they differ in fundamental ways. Most noticeably, the Cost of Debt is contractually defined and can be directly observed as the interest rate or yield on debt securities. The Cost of Equity, on the other hand, is neither directly observable nor a contractual obligation. Rather, equity investors have a claim on cash flows only after debt holders are paid; the uncertainty (or risk) associated with those residual cash flows determines the Cost of Equity. Because equity investors bear the "residual risk," they take greater risks and require higher returns than debt holders. In essence, equity and debt investors differ – they invest in different securities, face different risks, and require different returns.

Whereas the Cost of Debt can be directly observed, the Cost of Equity must be estimated or inferred based on market data applied to various financial models. As discussed throughout my Direct Testimony, each of those models is subject to certain assumptions, which may be more or less applicable under differing market conditions. Because the Cost of Equity is premised on opportunity costs, the models are typically applied to a group of "comparable" or "proxy" companies. The choice of models (including their inputs), the selection of proxy companies, and the interpretation of the model results all require the application of reasoned judgment. That judgment should consider data and information that is not necessarily included in the models themselves.

In the end, the estimated Cost of Equity should reflect the return that investors require in light of the subject company's risks, and the returns available on comparable investments. A given utility stock may require a higher return based on the risks to which it is exposed, or its expected growth, relative to other utilities. That is, although utilities may be viewed as a "sector," not all require the same return.

Q. Please briefly summarize the guidelines established by the United States Supreme Court (the "Supreme Court") for the purpose of determining the Return on Equity.

A. The Supreme Court established the guiding principles for establishing a fair return for capital in two cases: (1) *Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* ("*Bluefield*");[15] and (2) *Federal Power Comm'n v. Hope Natural Gas Co.* ("*Hope*").[16] In *Bluefield*, the Court stated:

> A public utility is entitled to such rates as will permit it to earn a return upon the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties[17]

The Supreme Court therefore recognized that: (1) a regulated public utility cannot remain financially sound unless the return it is allowed to earn on its invested capital is at least

---

15 *Bluefield Water Works and Improvement Co. v. Public Service Comm'n.*, 262 U.S. 679, 692 (1923).
16 *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).
17 *Bluefield Water Works and Improvement Co. v. Public Service Comm'n.*, 262 U.S. 679, 692 (1923).

equal to the Cost of Capital (the principle relating to the demand for capital); and (2) a regulated public utility will not be able to attract capital if it does not offer investors an opportunity to earn a return on their investment equal to the return they expect to earn on other investments of similar risk (the principle relating to the supply of capital).

In *Hope*, the Supreme Court reiterates the financial integrity and capital attraction principles of the *Bluefield* case:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[18]

In summary, the Supreme Court has recognized that the fair rate of return on equity should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain and support the company's credit and to attract capital. Intuitively, a fair rate of return satisfies all three standards.

Q. Does New Hampshire precedent provide similar guidance?

A. Yes. The Commission's decision in Order No. 26,007 stated that in determining just and reasonable rates, the Commission "balance[s] the interests of the customers' desire to pay no higher rates than reasonably necessary and the investors' right to earn a reasonable

[18] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

return on their investment."[19] Furthermore, the Commission's decision in Order No. 24,972 indicates that the Commission adheres to the capital attraction standard articulated in the *Hope* and *Bluefield* decisions.[20] Order No. 24,972 also states that the Commission is:

> [B]ound to set a rate of return that falls within a zone of reasonableness, neither so low to result in a confiscation of company property, nor so high as to result in extortionate charges to customers. A rate falling within that zone should, at a minimum, be sufficient to yield the cost of debt and equity capital necessary to provide the assets required for the discharge of the company's responsibility.[21]

Based on those standards, the authorized ROE should provide the Company with the opportunity (which is not a guarantee) to earn a fair and reasonable return and enable efficient access to external capital under a variety of market conditions.

Q. Why is it important for a utility to be allowed the opportunity to earn a return adequate to attract capital at reasonable terms?

A. A return that is adequate to attract capital at reasonable terms enables the utility to provide safe and reliable service while maintaining its financial integrity. As discussed above, and in keeping with the *Hope* and *Bluefield* standards, that return should be commensurate with the returns expected for investments of equivalent risk.

The ratemaking process is based on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility services, the utility must

---

[19] Unitil Energy Systems, Inc., *Petition for Distribution Rate Increase*, Docket No. DE 16-384, Order No. 26,007, at 17 (April 20, 2017).

[20] *See*, EnergyNorth Natural Gas, Inc. d/b/a National Grid NH, *Notice of Intent to File Rate Schedules*, Docket No. DG 08-009, Order No. 24,972, at 54-55 (May 29, 2009).

[21] *Ibid.*, at 54. *See also*, *Appeal of Conservation Law Foundation*, 127 N.H. 606 (N.H. 1986).

have the opportunity to recover the return of, and the market-required return on, invested capital. The allowed ROE should enable the subject utility to maintain its financial integrity in a variety of economic and capital market conditions. In order to preserve and enhance service reliability, UES must generate adequate cash flow from operations and have efficient access to external capital needed to undertake its capital investment plan regardless of the economic and capital market conditions at the time. A return that is adequate to attract capital at reasonable terms enables the utility to provide safe, reliable service while maintaining its financial soundness.

Further, the financial community carefully monitors utility companies' current and expected financial conditions, as well as the regulatory environment in which those companies operate. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' assessments of risk.[22] That consideration is especially important during uncertain economic and financial conditions in which the utility may require access to capital markets.

The outcome of the Commission's order in this case, therefore, should provide UES with the opportunity to earn an ROE that enables the Company to attract capital at reasonable terms in a variety of market environments, ensures its financial integrity, and is commensurate with returns on investments in enterprises having corresponding risks. To the extent UES is provided a reasonable opportunity to earn its market-based Cost of Equity, neither customers nor shareholders are disadvantaged. In fact, a return that is

---

[22] *See, e.g.*, Moody's Investor Service, *Rating Methodology: Regulated Electric and Gas Utilities*, June 23, 2017, at 4.

adequate to attract capital at reasonable terms enables UES to provide safe, reliable service while maintaining its financial integrity.

Q. Does the regulatory environment influence utilities' efficient access to capital?

A. Yes, it does. The regulatory environment is a key driver of investors' risk assessment for utilities. Investors and rating agencies understand that a constructive regulatory environment is critical to support utilities' credit ratings and financial integrity, especially during adverse market conditions.

Moody's Investors Service ("Moody's") considers the regulatory structure to be so important that 50.00 percent of the factors that weigh in a ratings determination are related to the nature of regulation.[23] Among the factors considered by Moody's in assessing the regulatory framework are the predictability and consistency of regulatory actions:

> As the revenues set by the regulator are a primary component of a utility's cash flow, the utility's ability to obtain predictable and supportive treatment within its regulatory framework is one of the most significant factors in assessing a utility's credit quality. The regulatory framework generally provides more certainty around a utility's cash flow and typically allows the company to operate with significantly less cushion in its cash flow metrics than comparably rated companies in other industrial sectors.
>
> ***
>
> In situations where the regulatory framework is less supportive, or is more contentious, a utility's credit quality can deteriorate rapidly.[24]

---

[23] *See*, Moody's Investors Service, Rating Methodology; *Regulated Gas and Electric Utilities*, at 4 (June 23, 2017).

[24] Moody's Investors Service, *Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities*, at 2 (June 18, 2010).

Similarly, as Standard & Poor's ("S&P") notes, "Regulatory advantage is the most heavily weighted factor when S&P Global Ratings analyzes a regulated utility's business risk profile."[25]

Q. How is the Cost of Equity estimated in regulatory proceedings?

A. Regulated utilities primarily use common stock and long-term debt to finance their permanent property, plant, and equipment. The rate of return for a regulated utility is based on its weighted average Cost of Capital, in which the costs of the individual sources of capital are weighted by their respective book values.

As noted earlier, the ROE is market-based and is estimated by applying observable market data to various financial models. By their nature, those models produce a range of results from which the ROE is determined. Although quantitative models are used to estimate the ROE, it cannot be precisely quantified through a strict mathematical solution. Other regulatory commissions have found no individual model is more reliable than all others under all market conditions.[26] Consistent with investor practice, it is both prudent and appropriate to use multiple methods to mitigate the effects of assumptions and inputs associated with any single approach. The key consideration in determining the ROE is to ensure the overall analysis reasonably reflects investors' view of financial

---

25 S&P Global Ratings, *Assessing U.S. Investor-Owned Utility Regulatory Environments*, at 2 (August 10, 2016).

26 *See, for example*: (1) Public Utilities Commission of the State of Hawaii, Docket No. 7700, Decision and Order No. 13704, *In the Matter of the Application of Hawaiian Electric Company, Inc. For Approval of Rate Increases and Revised Rate Schedules and Rules*, December 28, 1994 at 92; (2) The Commonwealth of Massachusetts Department of Public Utilities, *Investigation by the Department of Public Utilities*, Docket D.P.U. 15-155, September 30, 2016, at 376-378; and (3) State of North Carolina Utilities Commission, *In the Matter of Application of Public Service Company of North Carolina, Inc. for a General Increase in its Rates and Charges*, Docket No. G-5, Sub 565, Order Approving Rate Increase and Integrity Management Tracker, October 28, 2016, at 35-36.

markets in general, and the subject company (in the context of the proxy companies), in particular.

In summary, practitioners, academics, and regulatory commissions recognize that financial models are not precise quantifications of investor behavior but are tools to be used in the ROE estimation process. They appreciate that the strict adherence to any single approach, or to the specific results of any single approach, can lead to flawed or misleading conclusions.[27] A reasonable ROE estimate therefore considers multiple methods and the reasonableness of their individual and collective results in the context of observable, relevant market information.

B. Capital Market Environment

Q. Do economic conditions influence the required Cost of Capital and required return on common equity?

A. Yes. The required Cost of Capital, including the ROE, is a function of prevailing and expected economic and capital market conditions. As discussed below, the models used to estimate the Cost of Equity are influenced by current and expected capital market conditions. In addition, all analytical models used to estimate the required ROE are based on simplifying assumptions that may not hold true under certain market circumstances. Therefore, it is important to assess the reasonableness of any financial model's results in the context of observable market data. To the extent that certain ROE estimates are incompatible with such data or inconsistent with basic financial principles,

---

27 This is consistent with the *Hope* and *Bluefield* principle establishing it is the analytical result, as opposed to the method employed, that controls in determining just and reasonable rates.

it is appropriate to consider whether alternative estimation methods are likely to provide more meaningful and reliable results.

Q. Please describe the recent capital market dislocation and its implications for estimating the Company's Cost of Equity.

A. It is well recognized that there have been dramatic shifts in the capital markets brought about by the COVID-19 pandemic. The speed and severity of the increase in risk and the loss in value cut across all market sectors, including utilities. Notably:

- From February 12 to March 23, 2020, the Standard & Poor's ("S&P") 500 Index lost approximately 34.00 percent of its value, as did the utility sector.[28]
- At the same time, the Chicago Board Options Exchange ("CBOE") Volatility Index ("VIX", a measure of expected market volatility), increased six-fold (from 13.68 on February 14, 2020 to 82.69 on March 16, 2020).[29]
- On March 9, 2020, the 30-year Treasury yield fell below 1.00 percent for the first time.[30]

Although government and central bank actions have stabilized the capital markets somewhat, as explained in more detail below, volatility (and, therefore, risk) remain elevated for the utility sector, which has important implications on ROE analyses.

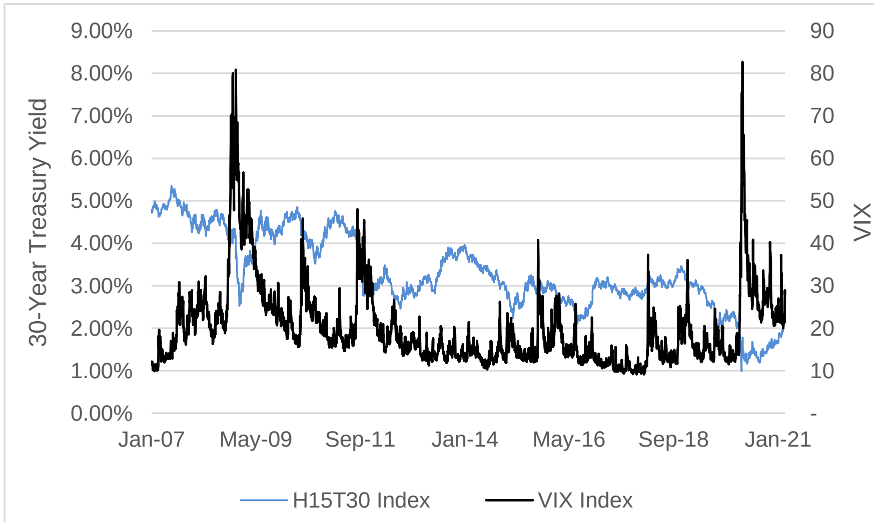
---

28 Source: Yahoo! Finance. Utility sector measured by the XLU and Dow Jones Utility Average.
29 Source: Bloomberg Professional Service.
30 Source: Bloomberg Professional Service.

Q. Is there a relationship between equity market volatility and interest rates?

A. Yes, there is. Significant and abrupt increases in volatility tend to be associated with declines in Treasury yields. That relationship makes intuitive sense; as investors see increasing risk, their objectives may shift principally to avoid capital losses (that is, capital preservation). A means of doing so is to allocate capital to the relative safety of Treasury securities, in a "flight to safety." Because Treasury yields tend to be inversely related to Treasury bond prices, as investors bid up the prices of bonds, they bid down the yields. As Chart 4 below demonstrates, decreases in the 30-year Treasury yield are coincident with significant increases in the VIX. In those instances, the decline in yields does not reflect a reduction in required returns, it reflects an increase in risk aversion and, therefore, an increase in required equity returns as investors favor the relative security of bonds during volatile markets. Simply put, in volatile markets, investors require higher returns to move from safe Treasury bond investments to riskier equity investments.

Chart 4: 30-Year Treasury Yields vs. VIX[31]



Q. Has volatility remained elevated relative to historical levels in recent months?

A. Yes. A visible and widely reported measure of expected volatility is the VIX. As CBOE explains, the VIX calculation is designed to produce a measure of constant, 30-day expected volatility of the U.S. stock market, derived from real-time, mid-quote prices of S&P 500 Index call and put options.[32] Simply, the VIX is a market-based measure of expected volatility. Because volatility is a measure of risk, increases in the VIX, or in its volatility, are a broad indicator of expected increases in market risk. That is, if the level of the VIX stood at 15.00, it would be interpreted as an expected standard deviation in annual market returns of 15.00 percent over the coming 30 days. Since 1990, the VIX has averaged about 19.49, which is consistent with the long-term standard deviation on

---

31 Source: Bloomberg Professional Service.
32 Source: www.cboe.com/vix.

annual market returns as reported by Duff & Phelps.[33] From February 12, 2020 to February 26, 2021, the VIX averaged 30.08, or more than 54.00 percent above its long-term average.[34] In other words, since the onset of the COVID-19 pandemic, market volatility has been approximately 54.00 percent higher on average than the market's long-term average volatility.

A further measure of market uncertainty is the volatility of the VIX itself. That is, we can look to the expected volatility of volatility, as measured by the CBOE VVIX Index ("VVIX"), which is a traded index of the expected volatility of the VIX. Over the long-term, the VVIX has averaged approximately 91.11. As Table 2 below shows, the average VVIX in 2020, and so far in 2021, was at its highest level since the index's inception in 2006.

---

33 Source: Duff & Phelps, 2020 SBBI Yearbook, at 6-17.
34 Source: Bloomberg Professional Service.

Table 2: Annual Average VVIX (2006-2021)[35]

Calendar Year	Average VVIX
2006	78.75
2007	87.68
2008	81.85
2009	79.78
2010	88.36
2011	92.94
2012	94.84
2013	80.64
2014	83.01
2015	94.82
2016	92.80
2017	90.01
2018	102.26
2019	91.00
2020	118.47
2021	119.01
Average 2006 - 2019	88.77
Average 2020 - 2021	118.54
Average 2006 - 2021	91.11

From a different perspective, the VVIX averaged 88.77 between 2006 and 2019; in 2020 and 2021, the average VVIX was approximately 34.00 percent higher (118.54), indicating that expected volatility is currently well above the long-term average. Stated differently, a relatively high VVIX suggests the VIX might be more volatile in the future, which in turn suggests expectations for higher market volatility in the future.

[35] Source: Bloomberg Professional Service.

The important analytical question is whether we can infer that historically low Treasury yields imply a Cost of Equity that is well below recently authorized returns. Given the inverse relationship between Treasury bond yields and the VIX, it is difficult to conclude that fundamental risk aversion and investor return requirements have fallen. Rather, the decline in Treasury yields signify an increase in investor-required equity returns, not a decrease, as equity investors require higher returns to compensate them for greater market risk.

Q. Is market volatility expected to remain elevated in the near term?

A. Yes. One means of assessing market expectations regarding the future level of volatility is to review CBOE's "Term Structure of Volatility", which is described by CBOE as:

> The implied volatility term structure observed in SPX options markets is analogous to the term structure of interest rates observed in fixed income markets. Similar to the calculation of forward rates of interest, it is possible to observe the option market's expectation of future market volatility through use of the SPX implied volatility term structure.[36]

As shown in Table 3 below, the implied volatility is expected to remain nearly 50.00 percent above historical volatility[37] until at least March 2022.

---

36 Source: www.cboe.com/trading-tools/strategy-planning-tools/term-structure-data.

37 The long-term average price of VIX is approximately 19.49, which, as discussed above, is similar to the long-term standard deviation of annual market returns.

Table 3: CBOE Term Structure of Volatility[38]

Date	Projected VIX
March 2021	28.21
April 2021	28.44
May 2021	29.59
June 2021	30.12
July 2021	30.71
August 2021	31.02
September 2021	31.75
December 2021	31.13
January 2022	29.15
March 2022	29.02

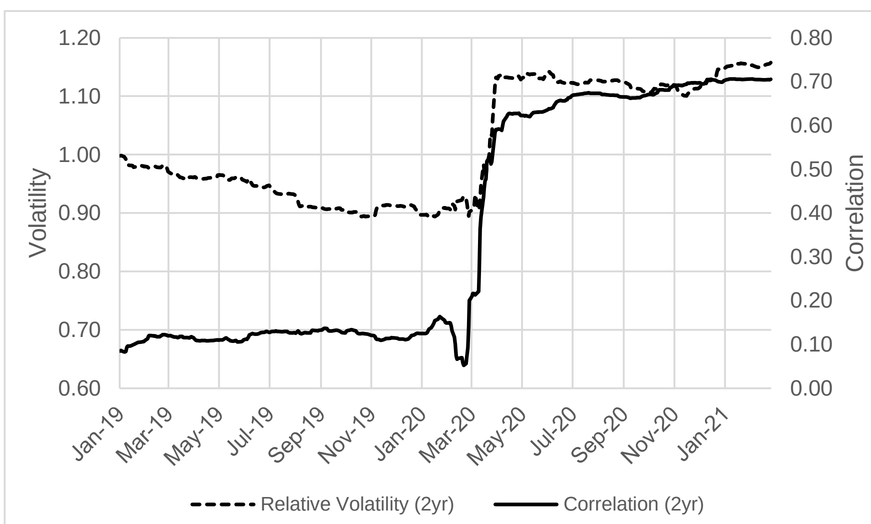
In short, investors reacted to the increase in market uncertainty associated with the COVID-19 pandemic by moving away from equity securities (including utilities) to Treasury securities, thereby pushing down long-term Treasury yields. Consequently, the current relatively low levels of interest rates are the result of a volatility-driven "flight to safety" on the part of investors, indicating increased risk aversion, and therefore a corresponding increase in investors' required equity returns. As shown in Chart 4 above, although volatility has declined somewhat from their March 2020 highs (as Treasury yields have begun to increase), it remains – and is expected to remain – above historical levels in the near term.

[38] Source: http://www.cboe.com/trading-tools/strategy-planning-tools/term-structure-data, as of February 26, 2021.

Q. Are there additional measures that indicate the Cost of Equity has increased for utilities?

A. Yes. As explained later in this section, Beta coefficients are a function of two parameters: (1) relative volatility (the standard deviation of the subject company's returns relative to the standard deviation of the market return); and (2) the correlation between the subject company's returns and the market return.[39] Under the CAPM, higher Beta coefficients indicate an increase in the Cost of Equity, all else equal. As Chart 5 below demonstrates, both the relative correlation and relative volatility between the proxy group and the overall market (as measured by the S&P 500) increased substantially in March 2020.

Chart 5: Components of Proxy Group (Two-Year) Beta Coefficients[40]



---

39 *See*, Equation [5].

40 Source: S&P Global Market Intelligence. Weekly returns calculated over 24 months.

This increase in correlation between returns for the proxy group and the S&P 500 is not surprising. As Morningstar recently explained, during volatile markets there often is little distinction in returns across assets or portfolios. That is, "correlations go to 1."[41] When that happens, utility stocks lose their "defensive" quality. Not surprisingly, the increased correlation and relative volatility combine to produce significantly increased (adjusted) Beta coefficients. As shown in Table 4, below, the average Beta coefficients for the proxy group reported by *Value Line* and Bloomberg increased by approximately 1.6x and 2.1x, respectively between February 2020 and February 2021.

Table 4: Average *Value Line* and Bloomberg Proxy Group Beta Coefficients[42]

Date	February 2020	February 2021
Value Line Average	0.557	0.877
Bloomberg Average	0.476	1.021

Q. Does your recommendation also consider the interest rate environment?

A. Yes, it does. As discussed below, prevailing interest rates have begun to increase. That increase is consistent with expectations for increases in U.S. economic growth and inflation.[43] From an analytical perspective, it is important that the inputs and assumptions used to arrive at an ROE recommendation, including assessments of capital market conditions, are consistent with the recommendation itself. Because the Cost of Equity is forward-looking, the salient issue is whether investors see the likelihood of

41 Morningstar, *Correlations Going to 1: Amid Market Collapse, U.S. Stock Fund Factors Show Little Differentiation*, March 6, 2020.
42 Sources: *Value Line* and Bloomberg Professional Service as of February 28, 2020 and February 26, 2021.
43 See, e.g., *Blue Chip Financial Forecasts*, Vol. 40, No. 3, March 1, 2021, at 1.

increased interest rates during the period in which the rates set in this proceeding will be in effect. With respect to long-term interest rates, the 50 economists surveyed by *Blue Chip Financial Forecast* ("*Blue Chip*") expect the 30-year Treasury yield to increase from the current 30-day average of 1.97 percent[44] to 2.80 percent on average over the five-year period 2022-2026.[45]

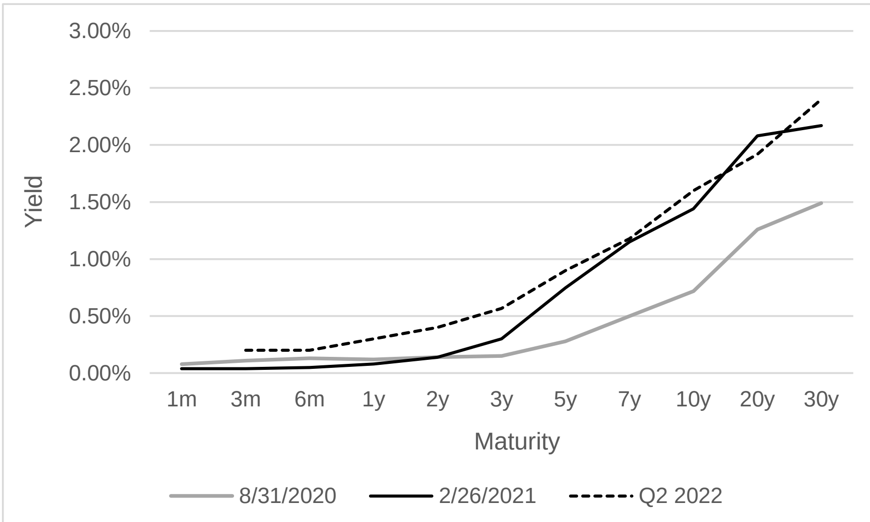
Q. Are there other indications that investors expect long-term interest rates to rise in the future?

A. Yes. Treasury bond prices, and therefore yields, are influenced by inflation expectations. As such, we can look to market data regarding investors' expectations for inflation as an indicator of future Treasury yields. As a recent article in *Barron's* explains, "While all Treasury yields reflect future interest rate expectations and inflation risk, longer-term securities' performance is more sensitive to rising interest rates and yields and their value is eroded by more inflation."[46] As such, when long-term Treasury yields increase faster than short-term yields (*i.e.*, the yield curve steepens), it is an indication that investors expect stronger economic growth and inflation.[47] As Chart 6 shows, the yield curve has steepened since August 2020, and is expected to widen further by the second quarter of 2022.

---

44 Source: Bloomberg Professional Service. *See*, Exhibit JEN-6.
45 *See*, Blue Chip Financial Forecasts, Vol. 39 No. 12, December 1, 2020, at 14.
46 Alexandra Scaggs, "The Yield Curve is the Steepest It Has Been in Years. Here's What That Means for Investors.", *Barron's*, February 4, 2021.
47 Alexandra Scaggs, "The Yield Curve is the Steepest It Has Been in Years. Here's What That Means for Investors.", *Barron's*, February 4, 2021.

Chart 6: Treasury Yield Curve[48]



Q. Has the Federal Reserve changed its inflation policy recently?

A. Yes, it has. On August 27, 2020, Federal Reserve Chair Jerome H. Powell released a statement noting that Federal Open Market Committee will take an approach towards inflation that "could be viewed as a flexible form of average inflation targeting", meaning that following periods in which inflation has run below 2.00 percent, "appropriate monetary policy will likely aim to achieve inflation moderately above 2 percent for some time."[49]

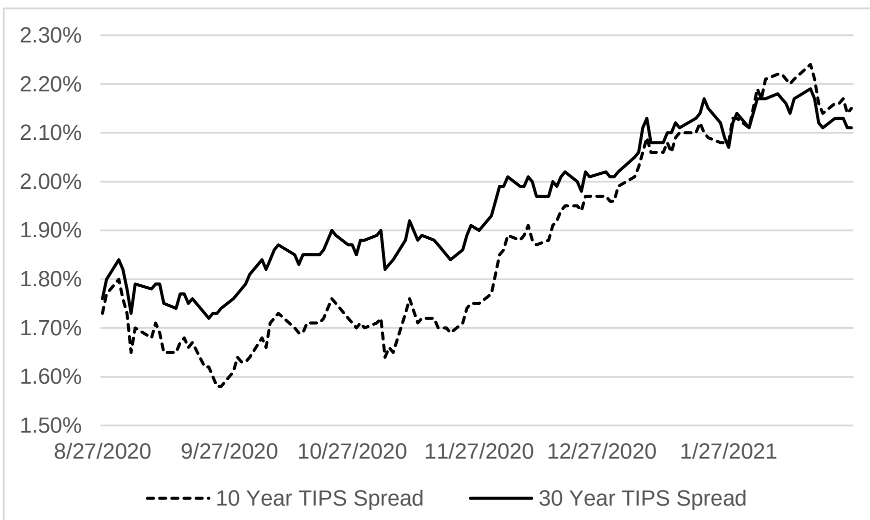
---

48 Source: Federal Reserve Board of Governors H.15 interest rate data. Q2 2022 projections from *Blue Chip Financial Forecasts*, Vol. 40, No. 3, March 1, 2021, at 2. Three-year, seven-year, and 20-year projected yields are interpolated.

49 *New Economic Challenges and the Fed's Monetary Policy Review*, Remarks by Jerome H. Powell, Chair Board of Governors of the Federal Reserve System, August 27, 2020, at 5.

Since Chairman Powell's remarks, the breakeven inflation rate of 10-year and 30-year Treasury securities,[50] represented as the spread between constant maturity Treasury securities and Treasury Inflation-Protected Securities ("TIPS"), has increased from 1.73 percent and 1.76 percent, respectively, to 2.15 percent and 2.11 percent respectively, as of February 26, 2021. Further, as shown in Chart 7 below, breakeven inflation has trended upward since the Federal Reserve's target inflation policy change at a relative consistent pace.

Chart 7: Breakeven Inflation Rate[51]



Given these market-based indications of higher inflation expectations in the future, it is reasonable to expect long-term Treasury yields to also increase.

---

50 The 10-year breakeven inflation rate represents a measure of expected inflation derived from 10-Year Treasury Constant Maturity Securities and 10-Year Treasury Inflation-Indexed Constant Maturity Securities. The latest value implies what market participants expect inflation to be in the next 10 years, on average. The 30-year breakeven inflation rate represents a measure of expected inflation derived from 30-Year Treasury Constant Maturity Securities and 30-Year Treasury Inflation-Indexed Constant Maturity Securities. The latest value implies what market participants expect inflation to be in the next 30 years, on average. Source: Federal Reserve Bank of St. Louis.

51 Source: Federal Reserve Board of Governors H.15 interest rate data.

Q. What conclusions do you draw from your review of the current capital market environment and its implications on the Company's Cost of Equity?

A. In short, during a period of heightened and possibly prolonged market uncertainty, observable market information makes clear that utility equity investors now face greater risks and therefore require higher returns. When markets become uncertain and disrupted, investors increase their equity return requirements. Estimating that additional return, however, becomes increasingly complex. When utility investors are faced with such extraordinary market uncertainty, regulatory supportiveness becomes critically important.

I appreciate that the Commission has the difficult task of balancing the interests of customers and investors. I also appreciate that doing so becomes increasingly difficult under stressed economic and financial conditions. However, one should not lose sight of the common interest customers and investors have in a financially strong utility, particularly during uncertain market environments. On balance, it is my opinion that the Company's Cost of Equity falls in the range of 9.90 percent to 10.50 percent. Although the uncertainty surrounding the scope and duration of the current market dislocation supports an ROE toward the upper end of my recommended range, an ROE of 10.20 percent is a reasonable, if not conservative, estimate of the Company's Cost of Equity, and balances the interests of utility customers and investors.

C. Proxy Group Selection

Q. As a preliminary matter, why is it necessary to select a group of proxy companies to determine the Cost of Equity for UES?

A. First, it is important to bear in mind that the Cost of Equity for a given enterprise depends on the risks attendant to the business in which the company is engaged. According to financial theory, the value of a given company is equal to the aggregate market value of its constituent business units. The value of the individual business units reflects the risks and opportunities inherent in the business sectors in which those units operate. In this proceeding, we are focused on estimating the Cost of Equity for UES, which is a wholly owned subsidiary of Unitil Corporation ("Unitil"). Because the ROE is a market-based concept, and UES is not a separate entity with its own stock price, it is necessary to establish a group of companies that are both publicly traded and comparable to the Company in certain fundamental respects to serve as its "proxy" in the ROE estimation process. Even if the Company were a publicly traded entity, short-term events could bias its market value during a given time period. A significant benefit of using a proxy group is that it moderates the effects of anomalous, temporary events associated with any one company.

Q. Does the selection of a proxy group suggest that analytical results will be narrowly clustered around average results?

A. Not necessarily. For example, the Constant Growth DCF approach defines the Cost of Equity as the sum of the expected dividend yield and projected long-term growth. Despite the care taken to ensure risk comparability, market expectations with respect to future risks and growth opportunities will vary from company to company. Therefore, even within a group of similarly situated companies, it is common for analytical results to reflect a seemingly wide range. Consequently, at issue is how to estimate the Cost of Equity from within that range. Such a determination necessarily must consider both quantitative and qualitative information.

Q. Please provide a summary profile of UES.

A. UES provides electric distribution service to approximately 66,000 residential and 11,000 commercial and industrial customers in New Hampshire.[52] The Company's service territory encompasses the capital city of Concord and various towns in the southeastern and seacoast regions of New Hampshire. UES has long-term ratings of BBB+ (Outlook: Negative) from S&P and Baa1 (Outlook: Stable) from Moody's. Unitil has long-term ratings of BBB+ (Outlook: Negative) from S&P and Baa2 (Outlook: Stable) from Moody's.[53]

Q. How did you select the companies included in your proxy group?

A. Because estimating the Cost of Equity is a comparative exercise, it is necessary to develop a proxy group of companies with risk profiles comparable to the subject company. In selecting a proxy group, my objective was to balance the competing interests of selecting companies that are representative of the risks and prospects faced by UES, while at the same time ensuring that there is a sufficient number of companies in the proxy group. Based on those two considerations, I began with the universe of

52 *See*, Unitil Corporation, SEC Form 10-K for the fiscal year ended December 31, 2020, at 3.
53 Source: S&P Global Market Intelligence.

companies that *Value Line* classifies as Electric Utilities, and applied the following screening criteria:

- Because certain of the models used in my analyses assume that earnings and dividends grow over time, I excluded companies that do not consistently pay quarterly cash dividends, or have cut their dividend within the last five years;
- To ensure that the growth rates used in my analyses are not biased by a single analyst, all the companies in my proxy group are consistently covered by at least two utility industry equity analysts;
- All the companies in my proxy group have investment grade senior unsecured bond and/or corporate credit ratings from S&P and/or Moody's;
- To incorporate companies that are primarily regulated electric utilities, I excluded companies with less than 60.00 percent of net operating income from regulated operations and 60.00 percent of regulated electric operating income, on average, over the last three years; and
- I eliminated companies that have recent merger activity (or other significant transaction) or have had a recent financial event that could affect its market data or financial condition.

Q. What companies met your screening criteria?

A. The criteria discussed above resulted in a proxy group of the following 24 companies:

Table 5: Proxy Group Screening Results

Company	Ticker
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avista Corporation	AVA
CMS Energy Corporation	CMS
Consolidated Edison, Inc.	ED
DTE Energy Company	DTE
Duke Energy Corporation	DUK
Entergy Corporation	ETR
Evergy, Inc.	EVRG
Eversource Energy	ES
Hawaiian Electric Industries, Inc.	HE
IDACORP, Inc.	IDA
NextEra Energy, Inc.	NEE
NorthWestern Corporation	NWE
OGE Energy Corp.	OGE
Otter Tail Corporation	OTTR
Pinnacle West Capital Corporation	PNW
Portland General Electric Company	POR
Public Service Enterprise Group Inc.	PEG
Southern Company	SO
WEC Energy Group, Inc.	WEC
Xcel Energy Inc.	XEL

D. Cost of Equity Models

Q. What analytical approaches did you use to determine the Company's ROE?

A. As noted earlier, I relied on the constant growth and quarterly forms of the DCF model, the traditional and empirical forms of the CAPM, and the Bond Yield Plus Risk Premium approach.

I rely on these models for two reasons. First, the purpose of an ROE analysis is to estimate the return that investors require; therefore, it is important to use the models on which investors rely. The models that I apply are commonly used in practice. Second, the models focus on different aspects of return requirements, and provide different insights to investors' views of risk and return. Using multiple methods provides a broader and, therefore, more reliable perspective on investors' return requirements.

1. Constant Growth DCF Model

Q. Please describe the Constant Growth DCF approach.

A. The Constant Growth DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. DCF theory assumes that an investor buys a stock for an expected total return rate, which is derived from cash flows received in the form of dividends plus appreciation in market price (the expected growth rate). In its simplest form, the Constant Growth DCF model expresses the Cost of Equity as the discount rate that sets the current price equal to expected cash flows:

$$P = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

where P represents the current stock price, $D_1 \ldots D_\infty$ represent expected future dividends, and k is the discount rate, or required ROE. Equation [1] is a standard present value calculation that can be simplified and rearranged into the familiar form:

$$k = \frac{D_0\ (1+g)}{P} + g \qquad [2]$$

Equation [2] often is referred to as the "Constant Growth DCF" model, in which the first term is the expected dividend yield, and the second term is the expected long-term annual growth rate in perpetuity.

Q. What assumptions underlie the Constant Growth DCF model?

A. The Constant Growth DCF model assumes: (1) a constant average annual growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant Price/Earnings multiple; and (4) a discount rate greater than the expected growth rate. The model also assumes that the current Cost of Equity will remain constant in perpetuity.

Q. What market data did you use to calculate the dividend yield in your Constant Growth DCF model?

A. The dividend yield is based on the proxy companies' current quarterly dividend multiplied by four, and the average closing stock prices over the 30-, 90-, and 180-trading day periods as of February 26, 2021.

Q. Why did you use three averaging periods to calculate an average stock price?

A. I did so to ensure that the model's results are not skewed by anomalous events that may affect stock prices on any given trading day. At the same time, the averaging period should be reasonably representative of expected capital market conditions over the long term. Using 30-, 90-, and 180-trading day averaging periods reasonably balances those concerns.

Q. Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A. Yes, I did. Because utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is appropriate to calculate the expected dividend yield by applying one-half of the long-term growth rate to the current dividend yield. That adjustment ensures that the expected dividend yield is, on average, representative of the coming 12-month period, and does not overstate the dividends to be paid during that time.

Q. What measures of long-term growth did you apply in the Constant Growth DCF model?

A. I have applied analysts' consensus projected earnings per share ("EPS") growth rates. In its Constant Growth form, the DCF model (*i.e.*, as presented in Equation [2] above) assumes a single expected growth estimate in perpetuity. Accordingly, in order to reduce the long-term growth rate to a single measure, one must assume a fixed payout ratio, and the same constant growth rate in EPS, dividends per share, and book value per share. Since dividend growth can only be sustained by earnings growth, the model should incorporate a variety of measures of long-term earnings growth. For the purposes of the

Constant Growth DCF model, therefore, growth in EPS represents the appropriate measure of long-term growth.

Q. Does academic research support the use of analysts' earnings growth projections as the appropriate measure for estimating equity returns in the Constant Growth DCF model?

A. Yes. The relationship between various growth rates and stock valuation metrics has been the subject of much academic research.[54] As noted over 40 years ago by Charles Phillips in The Economics of Regulation:

> For many years, it was thought that investors bought utility stocks largely on the basis of dividends. More recently, however, studies indicate that the market is valuing utility stocks with reference to total per share earnings, so that the earnings-price ratio has assumed increased emphasis in rate cases.[55]

Subsequent academic research has clearly and consistently indicated that measures of earnings and cash flow are strongly related to returns, and that analysts' forecasts of growth are superior to other measures of growth in predicting stock prices.[56] For example, Vander Weide and Carleton state that, "[our] results … are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy-and-sell decisions."[57] Other research specifically notes

---

54 *See*, Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management (Spring 1986).

55 Charles F. Phillips, Jr., The Economics of Regulation, at 285 (Rev. ed. 1969).

56 *See, e.g.*, Andreas C. Christofi, Petros C. Christofi, Marcus Lori and Donald M. Moliver, *Evaluating Common Stocks Using Value Line's Projected Cash Flows and Implied Growth Rate*, Journal of Investing (Spring 1999); Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, 21 (Summer 1992); and James H. Vander Weide and Willard T. Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988).

57 James H. Vander Weide and Willard T. Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management, at 81 (Spring 1988).

the importance of analysts' growth estimates in determining the Cost of Equity, and in the valuation of equity securities. Dr. Robert Harris noted that "a growing body of knowledge shows that analysts' earnings forecasts are indeed reflected in stock prices." Citing Cragg and Malkiel, Dr. Harris notes that those authors "found that the evaluations of companies that analysts make are the sorts of ones on which market valuation is based."[58] Similarly, Brigham, Shome, and Vinson noted that "evidence in the current literature indicates that (i) analysts' forecasts are superior to forecasts based solely on time series data; and (ii) investors do rely on analysts' forecasts."[59]

To that point, the research of Vander Weide and Carleton demonstrates that earnings growth projections have a statistically significant relationship to stock valuation levels, while dividend growth rates do not.[60] Those findings suggest that investors form their investment decisions based on expectations of growth in earnings, not dividends. Consequently, earnings growth, not dividend growth, is the appropriate estimate for the purpose of the Constant Growth DCF model.

Q. Did you consider additional measures of projected growth rates beyond projected earnings growth estimates?

A. For the reasons explained above, projected earnings growth estimates are the appropriate measure of growth for use in the DCF model. However, I understand that in recent

---

58 Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management, at 56 (Spring 1986).

59 Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, at 36 (Spring 1985).

60 *See*, James H. Vander Weide and Willard T. Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988).

proceedings before the Commission, projected dividend growth rates and book value growth rates have been considered by ROE witnesses in their DCF analyses. Therefore, to assess the reasonableness of the projected earnings growth rates applied in my DCF analysis, I reviewed *Value Line's* average and median long-term projected dividend growth rates and projected book value growth rates for the proxy companies. As Table 6 below shows, the average and median proxy group projected earnings growth rates of 5.39 percent and 5.71 percent, respectively, are generally within *Value Line's* average and median projected dividend growth rates and book value growth rates[61] for the proxy companies.

Table 6: Comparison of Growth Rate Projections for the Proxy Group

	Earnings Growth[62]	***Value Line* Dividend Growth[63]**	***Value Line* Book Value Growth[64]**
Average	5.39%	5.23%	4.19%
Median	5.71%	5.50%	3.75%

Moreover, as explained below, I calculate a range of DCF-based ROE estimates based on the lowest and highest earnings growth rates; therefore, my DCF analyses reflect a wide range of growth rate expectations. In other words, the earnings growth projections applied in my DCF analyses generally encompass *Value Line's* projected dividend growth and book value growth rates shown in Table 6 above. For these reasons, I

---

61 *Value Line* is the only source I am aware of that provides dividend and book value growth rate projections.
62 Average of Zacks, Yahoo! Finance, and *Value Line*. *See*, Exhibit JEN-3.
63 Source: *Value Line* five-year dividend growth estimate.
64 Source: *Value Line* five-year book value growth estimate.

conclude the earnings growth projections applied in the DCF analyses are reasonable and appropriate.

Q. Please summarize your inputs to the Constant Growth DCF model.

A. I applied the Constant Growth DCF model to the proxy group of electric utility companies using the following inputs for the price and dividend terms:

- The average daily closing prices for the 30-, 90-, and 180-trading days ended February 26, 2021, for the term P_0; and
- The annualized dividend per share as of February 26, 2021, for the term D_0.

I then calculated my Constant Growth DCF results using each of the following growth terms:

- *Value Line's* long-term earnings growth estimates;
- Zacks' consensus long-term earnings growth estimates; and
- First Call's consensus long-term earnings growth estimates.

Q. How did you calculate the DCF results?

A. For each proxy company, I calculated the low, mean, and high DCF results. For the mean result, I combined the average of the three EPS growth rate estimates listed above with the subject company's expected dividend yield for each proxy company and then calculated the mean and median result for those estimates. I calculated the high DCF result by combining the maximum EPS growth rate estimate with the subject company's expected dividend yield. I used the same approach to calculate the low DCF result, using instead the minimum EPS growth estimate for each proxy company. Finally, I calculated the average of the mean and median low, mean, and high DCF results for the proxy group to develop the Constant Growth DCF results summarized in Table 7 below (*see also*, Exhibit JEN-3).

Table 7: Constant Growth DCF Results[65]

	Low	**Mean**	**High**
30-Day Average	8.45%	9.20%	9.83%
90-Day Average	8.44%	9.06%	9.75%
180-Day Average	8.48%	9.09%	9.84%

2. Quarterly Growth DCF Model

Q. Please describe the Quarterly Growth DCF model.

A. As noted earlier, the Constant Growth DCF model is based on several limiting assumptions, one of which is that dividends are paid annually. However, most dividend-paying companies, including utilities, pay dividends on a quarterly (as opposed to an annual) basis. Although the dividend yield adjustment discussed earlier is meant to address that assumption (by increasing the observed dividend yield by one-half of the expected growth rate), it does not fully reflect the quarterly receipt and reinvestment of dividends. As a consequence, the Constant Growth DCF model likely understates the Cost of Equity. The Quarterly Growth DCF model specifically incorporates investors' expectations of the quarterly payment of dividends, and the associated quarterly compounding of those dividends as they are reinvested at the required ROE. As noted by Dr. Roger Morin:

65 *See*, Exhibit JEN-3. Average of the proxy group mean and median results.

> Clearly, given that dividends are paid quarterly and that the observed stock price reflects the quarterly nature of dividend payments, the market-required return must recognize quarterly compounding, for the investor receives dividend checks and reinvests the proceeds on a quarterly schedule... The annual DCF model inherently understates the investors' true return because it assumes all cash flows received by investors are paid annually.[66]

Q. How is the dividend yield portion of the Quarterly DCF model calculated?

A. To more accurately reflect the timing and compounding of quarterly dividends, the model replaces the "D" component of the Constant Growth DCF model with the following equation:

$$D = d_1 (1 + k)^{0.75} + d_2 (1 + k)^{0.50} + d_3 (1 + k)^{0.25} + d_4 (1 + k)^{0} \quad [3]$$

where:

d_1, d_2, d_3, d_4 = expected quarterly dividends over the coming year; and

k = the required Return on Equity.

Because the required ROE (k) is a variable in the dividend calculation, the Quarterly Growth DCF model is solved in an iterative fashion.

To calculate the expected dividends over the coming year for the proxy companies (*i.e.*, d_1, d_2, d_3, and d_4), I obtained the last four paid quarterly dividends for each company and multiplied them by one plus the growth rate (*i.e.*, $1 + g$). For the P_0 component of the dividend yield, I used the same average stock prices applied in the Constant Growth DCF analysis (*i.e.*, 30-, 90-, and 180-trading day averages ended February 26, 2021 for each proxy company.

---

[66] Roger A. Morin, Ph.D., New Regulatory Finance, at 344 (2006).

Q. What are the results of your Quarterly Growth DCF analyses?

A. My Quarterly Growth DCF results are summarized in Table 8 below (*see also*, Exhibit JEN-4).

Table 8: Quarterly Growth DCF Results[67]

	Low	Mean	High
30-Day Average	8.55%	9.29%	9.99%
90-Day Average	8.52%	9.14%	9.91%
180-Day Average	8.55%	9.21%	9.99%

Q. Earlier you stated that more weight should be given to the upper end of the DCF results given the current economic and capital market environments. Why do you believe it is reasonable to give more weight to the high end of the DCF results that is based on the highest earnings growth rate projections?

A. It is reasonable and appropriate to rely on the high end of the DCF model results for several reasons. First, as explained earlier, the fundamental relationship between dividend yields and expected growth rates does not appear to currently hold. The average and median high projected earnings growth rates for the proxy group are 6.20 percent and 6.00 percent, respectively. Those growth rates are consistent with the proxy group's average annual capital appreciation rate noted earlier of 6.28 percent,[68] as well as the long-term compound average annual GDP growth rate of 6.00 percent.[69] Consequently,

67 *See*, Exhibit JEN-4. Average of the proxy group mean and median results.
68 Proxy Group calculated as an Index.
69 Source: U.S. Bureau of Economic Analysis as of February 25, 2021. Compound annual average growth from 1929-2020.

it is reasonable to give more weight to the high earnings growth estimates and, therefore, the High DCF results.

In the end, it is the reasonableness of the ROE itself, rather than the approach used in its estimation, that is paramount in determining just and reasonable rates. An ROE that meets the *Hope* and *Bluefield* standards is one that is comparable to returns available to other utilities of similar risk. As shown in Exhibit JEN-3 and Exhibit JEN-4, the mean and median High DCF results range from approximately 9.60 percent to nearly 10.20 percent. Between January 2017 and February 2021, the average authorized ROE for electric utilities was 9.64 percent; for the operating companies within the proxy group, the average was 9.65 percent.[70] Moreover, during that same period, more than 54.00 percent of authorized ROEs for electric utilities were 9.60 percent or higher, whereas approximately 12.00 percent were within the range of the Low and Mean DCF results (below 9.30 percent). Moreover, more than 25.00 percent were 9.90 percent (the low end of my recommended range) and higher. From that perspective, the High DCF results are more consistent with recently authorized ROEs for electric utilities, including the proxy group, than are the low and mean DCF results. For these reasons, it is reasonable to give more weight to the High DCF results.

[70] Source: Regulatory Research Associates. Excludes ROEs authorized as part of Illinois or Vermont Formula Rate Plans that are tied to U.S. Treasury bond yields and the 8.25% ROE authorized for Central Maine Power in February 2020 as it included a 100-basis point management penalty.

3. Capital Asset Pricing Model and Empirical Capital Asset Pricing Model

Q. Please describe the general form of the CAPM.

A. The CAPM is a risk premium method that estimates the Cost of Equity for a given security as a function of a risk-free return plus a risk premium (to compensate investors for the non-diversifiable or "systematic" risk of that security). The CAPM describes the relationship between a security's investment risk and the market rate of return. The CAPM assumes that all non-market or unsystematic risk can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. In addition, the CAPM presumes that investors require compensation only for systematic risk that is the result of macroeconomic and other events that affect the returns on all assets.

As shown in Equation [4], the CAPM is defined by four components, each of which theoretically is a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \qquad [4]$$

where:

K_e = the required market ROE for a security;

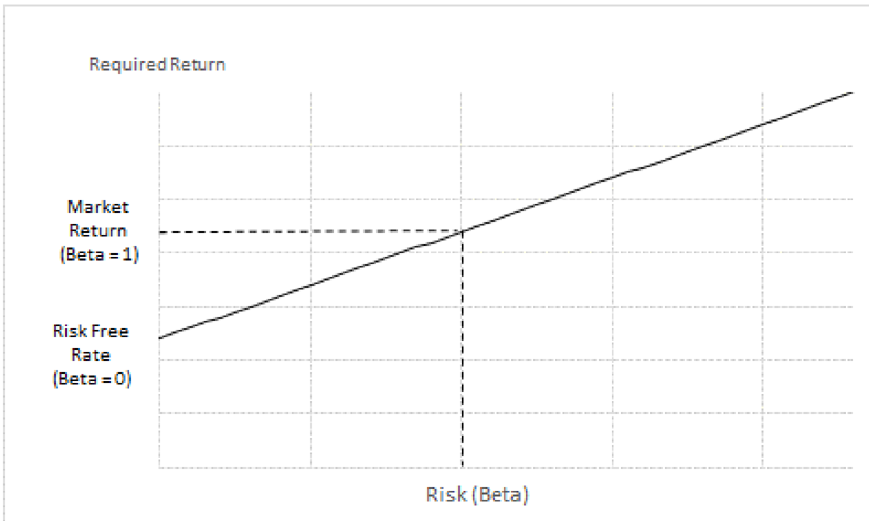
β = the Beta coefficient of that security;

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

Equation [4] describes the Security Market Line ("SML"), or the CAPM risk-return relationship, which is graphically depicted in Chart 8 below. The intercept is the risk-free rate (r_f) which has a Beta coefficient of zero, and the slope is the expected market risk premium ($r_m - r_f$). By definition, r_m, the return on the market, has a Beta coefficient of 1.00. CAPM states that in well-behaving capital markets, the expected equity risk premium on a given security is proportional to its Beta coefficient.

Chart 8: Security Market Line



Intuitively, higher Beta coefficients indicate that the subject company's returns have been relatively volatile and have moved in tandem with the overall market. Consequently, if a company has a Beta coefficient of 1.00, it is as risky as the market and does not provide any diversification benefit.

In Equation [4], the term ($r_m - r_f$) represents the Market Risk Premium ("MRP").[71] According to the theory underlying the CAPM, since unsystematic risk can be diversified away by adding securities to investment portfolios, the market will not compensate investors for bearing that risk. Therefore, investors should be concerned only with

[71] The MRP is defined as the incremental return of the market portfolio over the risk-free rate.

systematic or non-diversifiable risk. Non-diversifiable risk is measured by the Beta coefficient, which is defined as:

$$\beta_j = \frac{\sigma_j}{\sigma_m} \text{ x } \rho_{j,m} \quad [5]$$

where σ_j is the standard deviation of returns for company "*j*," σ_m is the standard deviation of returns for the broad market (as measured, for example, by the S&P 500 Index), and $\rho_{j,m}$ is the correlation of returns between company *j* and the broad market. The Beta coefficient, therefore, represents both relative volatility (*i.e.*, the standard deviation) of returns, and the correlation in returns between the subject company and the overall market.

Q. What risk-free rates did you assume in your CAPM analysis?

A. I used two different estimates of the risk-free rate: (1) the current 30-day average yield on 30-year Treasury bonds (*i.e.*, 1.97 percent)[72] and (2) a projected 30-year Treasury yield (*i.e.*, 2.72 percent).[73]

Q. Why have you relied upon the 30-year Treasury yield for your CAPM analysis?

A. In determining the security most relevant to the application of the CAPM, it is important to select the term (or maturity) that best matches the life of the underlying investment. Electric utilities typically are long-term investments and, as such, the 30-year Treasury yield is more suitable for the purpose of calculating the Cost of Equity.

72 Source: Bloomberg Professional Service.

73 The average of: (1) the average projected 30-year Treasury yield for the six quarters ended Q2 2022; and (2) the average long-term projected 30-year Treasury yield for the years 2022-2026 and 2027-2031 reported by *Blue Chip Financial Forecast. See*, *Blue Chip Financial Forecasts*, Vol. 40, No. 3, March 1, 2021, at 2 and *Blue Chip Financial Forecasts*, Vol. 39, No. 12, December 1, 2020, at 14.

Q. What Beta coefficients did you use in your CAPM model?

A. It is my usual practice to consider the Beta coefficients reported by two sources: Bloomberg and *Value Line*. Both of those services adjust their calculated (or "raw") Beta coefficients to reflect the tendency of the Beta coefficient to regress toward the market mean of 1.00; *Value Line* calculates the Beta coefficient over a five-year period, while Bloomberg's calculation is based on two years of data. The proxy group mean and median Beta coefficients from *Value Line* and Bloomberg are shown in Table 9 below.

Table 9: Proxy Group Beta Coefficients[74]

	Value Line	**Bloomberg**
Proxy Group Average	0.877	1.021
Proxy Group Median	0.850	1.027

To be conservative, I have relied on the *Value Line* Beta coefficients in my CAPM and Empirical CAPM ("ECAPM") analyses.

Q. Please describe your forward-looking (*i.e.*, *ex-ante*) approach to estimating the market required return.

A. It is my usual practice to develop two estimates of the market required return by calculating the market capitalization-weighted average ROE based on the Constant Growth DCF model for the S&P 500 companies using data from Bloomberg and *Value Line (see* Exhibit JEN-5*)*. With respect to Bloomberg-derived growth estimates, I calculated the expected dividend yield (using the same one-half growth rate assumption

[74] Sources: *Value Line* and Bloomberg Professional Services as of February 26, 2021.

described earlier) and combined that amount with the projected earnings growth rate to arrive at the market capitalization weighted average DCF result. I performed that calculation for each of the S&P 500 companies for which Bloomberg provided consensus growth rates, which produces an expected market required return of 16.35 percent. In the case of *Value Line*, I performed the same calculation, again using all companies for which five-year earnings growth rates were available, which produces an expected market required return of 14.34 percent.

While my usual practice is to apply the average of the Bloomberg-derived and *Value Line*-derived expected market return estimates, in order to be conservative, my CAPM and ECAPM analyses presented in my Direct Testimony rely on the *Value Line*-derived expected market return estimate.

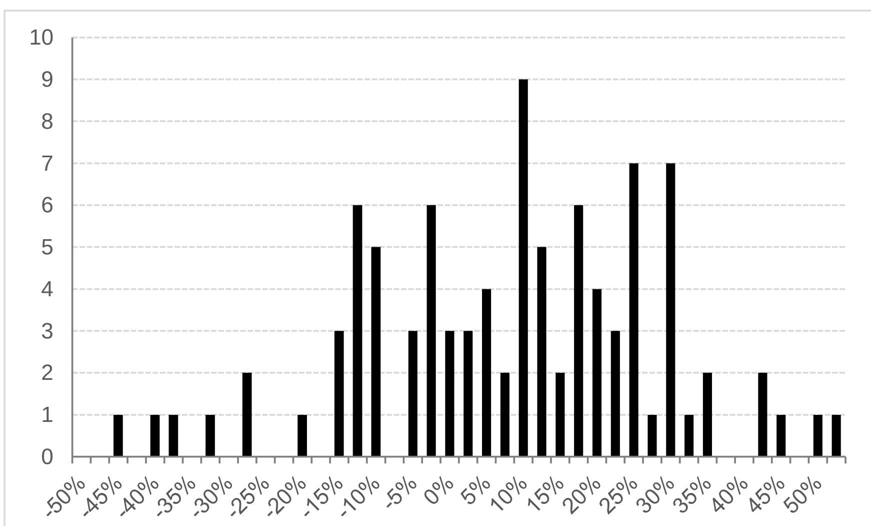
Q. With the risk-free rates and *ex-ante* market required return estimates described above, how did you calculate the MRP?

A. Because I apply two estimates of the risk-free rate, I calculated two estimates of the MRP. The first MRP estimate takes the *Value Line ex-ante* market required return described above (14.34 percent) and subtract the current 30-day average 30-year Treasury yield (1.97 percent). My second MRP estimate subtracts the projected 30-year Treasury yield (2.72 percent) *Value Line ex-ante* market required return (14.34 percent). These calculations result in *ex-ante* MRP estimates using the current and projected 30-year Treasury yield of 12.37 percent and 11.62 percent, respectively.

Q. Have you undertaken any analyses to determine the reasonableness of your *ex-ante* MRP estimates?

A. Yes. To do so, I considered how often various ranges of MRPs have been observed over the 1926 to 2019 period. To perform that analysis, I gathered the annual Market Risk Premia reported by Duff & Phelps and produced a histogram of those observations. The results of that analysis, which are presented in Chart 9, demonstrate that MRPs in the range of 12.00 percent (the average of my *Value Line*-derived MRP estimates) and higher occurred quite frequently, approximately 42.00 percent of the time.

Chart 9: Frequency Distribution of MRP (1926-2019)[75]



75 Source: Duff & Phelps, 2020 SBBI Yearbook, Appendix A-1, A-7.

Q. What are the results of your CAPM analysis?

A. As shown in Table 10, the proxy group average and median CAPM results using the MRP and Beta coefficients based on *Value Line* data suggest an ROE range of 12.48 percent to 12.91 percent (*see also*, Exhibit JEN-6).

Table 10: Summary of CAPM Results[76]

	Current 30-Year Treasury Yield (1.97%)	**Projected 30-Year Treasury Yield (2.72%)**
Proxy Group Average	12.82%	12.91%
Proxy Group Median	12.48%	12.59%

Q. Did you consider another form of the CAPM in your analysis?

A. Yes. I also included the ECAPM approach, which calculates the product of the adjusted Beta coefficient and the Market Risk Premium and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the Market Risk Premium, without any effect from the Beta coefficient.[77] The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [6] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \quad [6]$$

where:

k_e = the required market ROE;

β = the adjusted Beta coefficient of an individual security;

76 *See*, Exhibit JEN-6. *Value Line*-based results.
77 *See, e.g.*, Roger A. Morin, Ph.D., New Regulatory Finance, at 189-190 (2006).

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

Q. What is the benefit of the ECAPM approach?

A. The ECAPM addresses the tendency of the CAPM to under-estimate the Cost of Equity for companies, such as regulated utilities, with low Beta coefficients. As discussed below, the ECAPM recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM under-estimates the alpha, or the constant return term.[78]

Numerous tests of the CAPM have measured the extent to which security returns and Beta coefficients are related as predicted by the CAPM. The ECAPM method reflects the finding that the actual SML described by the CAPM formula is not as steeply sloped as the predicted SML.[79] Fama and French state that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[80] Similarly, Dr. Morin states:

> With few exceptions, the empirical studies agree that . . . low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. . . .
>
> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:

---

78 *Ibid*., at 191 ("The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks.").

79 *Ibid*., at 175. The Security Market Line plots the CAPM estimate on the Y-axis, and Beta coefficients on the X-axis.

80 Eugene F. Fama & Kenneth R. French, *The Capital Asset Pricing Model: Theory and Evidence*, Journal of Economic Perspectives, Vol. 18, No. 3, Summer 2004, at 33.

$$K = R_F + x\,(R_M - R_F) + (1-x)\beta(R_M - R_F)$$

> where x is a fraction to be determined empirically. The value of x that best explains the observed relationship Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:

$$K = R_F + 0.25(R_M - R_F) + 0.75\,\beta(R_M - R_F)$$[81]

Q. Does the application of adjusted Beta coefficients in the ECAPM address the empirical issues with the CAPM?

A. No, it does not. Beta coefficients are adjusted because of their general regression tendency to converge toward 1.00 over time, *i.e.*, over successive calculations. As also noted earlier, numerous studies have determined that at any given point in time, the SML described by the CAPM formula is not as steeply sloped as the predicted SML. To that point, Dr. Morin states:

> Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to Figure 6-1, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary.[82]

---

[81] Roger A. Morin, Ph.D., New Regulatory Finance, at 175, 190 (2006).
[82] *Ibid.*, at 191.

Therefore, it is appropriate to rely on adjusted Beta coefficients in both the CAPM and ECAPM. As with the CAPM, my application of the ECAPM uses the Market DCF-derived *ex-ante* MRP estimate from *Value Line*, the current yield and projected yield on 30-year Treasury securities as the risk-free rate, and the *Value Line* Beta coefficient. The results of my ECAPM analyses are shown on Exhibit JEN-6 and summarized in Table 11 below.

Table 11: Summary of Empirical CAPM Results[83]

	Current 30-Year Treasury Yield (1.97%)	Projected 30-Year Treasury Yield (2.72%)
Proxy Group Average	13.20%	13.27%
Proxy Group Median	12.95%	13.03%

4. Bond Yield Plus Risk Premium Approach

Q. Please describe the Bond Yield Plus Risk Premium approach.

A. The Bond Yield Plus Risk Premium approach is based on the basic financial principle of risk and return; that is, equity investors require a premium over the return they would have earned as a bondholder to account for the residual risk associated with equity ownership. In other words, since returns to equity holders are riskier than returns to bondholders, equity investors must be compensated for bearing that additional risk. Risk Premium approaches, therefore, estimate the Cost of Equity as the sum of the Equity Risk Premium and the yield on a particular class of bonds.

[83] *See*, Exhibit JEN-6. *Value Line*-based estimates.

Q. Please explain how you performed your Bond Yield Plus Risk Premium analysis.

A. I first defined the Equity Risk Premium as the difference between the authorized ROE and the 30-year Treasury yield. I then gathered data for 1,657 electric utility rate proceedings between January 1, 1980 and February 26, 2021. To reflect the prevailing level of interest rates during the pendency of the proceedings, I calculated the average 30-year Treasury yield over the average period between the filing of the case and the date of the final order (approximately 200 days).

Because the data cover a number of economic cycles, the analysis also may be used to assess the change in the Equity Risk Premium over time. Prior research, for example, has shown that the Equity Risk Premium is inversely related to the level of interest rates.[84] That analysis is particularly relevant given the relatively low level of current Treasury yields.

Q. How did you analyze the relationship between interest rates and the Equity Risk Premium?

A. To analyze the relationship between interest rates and the Equity Risk Premium, I performed a regression analysis, in which the observed Equity Risk Premium is the dependent variable, and the average 30-year Treasury yield is the independent variable. To account for the variability in interest rates and authorized ROEs over several decades,

---

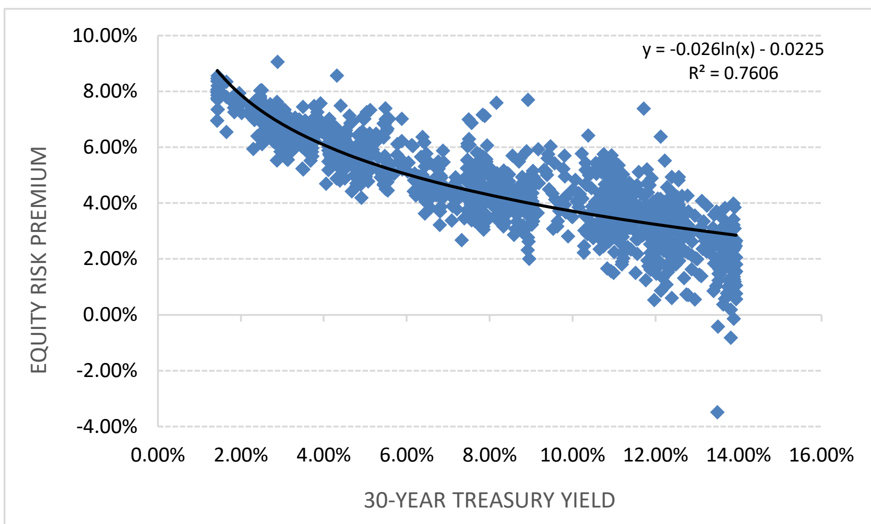
[84] *See, for example*, Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, (Summer 1992), at 63-70; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, (Spring 1985), at 33-45; and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management, (Autumn 1995), at 89-95.

I used the semi-log regression, in which the Equity Risk Premium is expressed as a function of the natural log of the 30-year Treasury yield:

$$RP = \alpha + \beta\,(\mathrm{LN}(T_{30})) \quad [7]$$

As shown on Chart 10 (below), the semi-log form is useful when measuring an absolute change in the dependent variable (in this case, the Equity Risk Premium) relative to a proportional change in the independent variable (the 30-year Treasury yield).

Chart 10: Equity Risk Premium[85]



As Chart 10 illustrates, over time there has been a statistically significant, negative relationship between the 30-year Treasury yield and the Equity Risk Premium. Based on the regression coefficients in Chart 10, the implied ROE is between 9.89 percent and 9.80 percent (*see*, Table 12 below and Exhibit JEN-7).

[85] *See*, Exhibit JEN-7.

Table 12: Summary of Bond Yield Plus Risk Premium Results[86]

	Return on Equity
Current 30-Year Treasury Yield (1.97%)	9.89%
Projected 30-Year Treasury Yield (2.72%)	9.80%

Q. Is your Bond Yield Plus Risk Premium analysis forward-looking?

A. Yes, it is. As explained earlier, because the Cost of Equity is forward-looking, it is important to apply forward-looking inputs and methodologies to estimate the Cost of Equity. Although the analysis incorporates historical authorized ROEs and 30-year Treasury yields to model the long-term relationship between the Equity Risk Premium and Treasury yields through a regression analysis, the analysis applies current and projected interest rates to the regression coefficients to produce forward-looking ROE estimates.

IV. <u>BUSINESS RISKS AND OTHER CONSIDERATIONS</u>

Q. Do the mean model results for the proxy group provide an appropriate estimate for the Cost of Equity for UES?

A. No, the mean model results do not necessarily provide an appropriate estimate of the Cost of Equity for UES. In my view, there are additional factors that must be taken into consideration when determining where the Company's Cost of Equity falls within the range of results. Specifically, I considered (1) UES's small size relative to the proxy group and (2) the Company's proposed revenue decoupling mechanism. As discussed

86 *See*, Exhibit JEN-7.

below, these elements should be considered in terms of their overall effect on UES's business risk and, therefore, its Cost of Equity.

A. Small Size Effect

Q. Please explain the implications on the Cost of Equity associated with the small size of a firm.

A. Both the financial and academic communities have long accepted the proposition that the Cost of Equity for small firms is subject to a "size effect."[87] While empirical evidence of the size effect often is based on studies of industries beyond regulated utilities, utility analysts also have noted the risks associated with small market capitalizations. Specifically, a senior consultant with Ibbotson Associates noted:

> For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return.[88]

Small size, therefore, leads to two categories of increased risk for investors: (1) liquidity risk (*i.e.*, the risk of not being able to sell one's shares in a timely manner due to the relatively thin market for the securities); and (2) fundamental business risks.

Q. How does the smaller size of UES affect its business risks relative to the proxy group?

A. It is important to bear in mind that my ROE recommendation for UES is developed based on market data applied to a risk-comparable proxy group. Consequently, an evaluation of the Company's risk associated with its small size is necessarily based on a comparison of

---

[87] *See*, Mario Levis, *The record on small companies: A review of the evidence*, Journal of Asset Management, March 2002, at 368-397, for a review of literature relating to the size effect.

[88] Michael Annin, *Equity and the Small-Stock Effect,* Public Utilities Fortnightly, at 1 (October 15, 1995).

its size relative to the proxy group. The Company's smaller size relative to the proxy companies indicates greater relative business risk for the Company because, all else equal, size has a material bearing on risk.

In general, smaller companies, including regulated utilities, are less able to withstand adverse events that affect their revenues and expenses. Any material changes to expected operations and maintenance expenses can have severe consequences on a company's level of operating leverage. For example, smaller companies face more risk exposure to business cycles and economic conditions, both nationally and locally. Taken together, these risks affect the return required by investors for smaller companies.

Q. Is there support in the financial community for the use of a small size premium?

A. Yes. There have been several studies that demonstrate the existence of the size premium. One of the earliest works in this area found that over a period of 40 years "the common stock of small firms had, on average, higher risk-adjusted returns than the common stock of large firms."[89] The author, who referred to that finding as the "size effect," suggested that the CAPM was mis-specified in that, on average, smaller firms had significantly larger risk-adjusted returns than larger firms. The author also concluded that the size effect was "most pronounced for the smallest firms in the sample."[90] Since then, additional empirical research has focused on explaining the size effect as a function of

---

[89] R. W. Banz, *The Relationship Between Return and Market Value of Common Stocks*, Journal of Financial Economics, at 3-4 (1981).

[90] *Ibid*., at 16.

lower trading volume and other factors, but the proposition that Beta coefficients fail to reflect the risks of smaller firms persists.[91]

In 1994, Fama and French focused on the issue of whether the CAPM adequately explained security returns and proposed a "three factor" model for expected security returns. Those factors include: (1) the covariance with the market, (2) size, and (3) financial risk as determined by the book-to-market ratio. As explained by Morningstar, Fama and French "found that the returns on stocks are better explained as a function of size and book-to-market value in addition to the single market factor of the CAPM, with the company's size capturing the size effect and its book-to-market ratio capturing the financial distress of a firm."[92]

Simply put, investors generally demand greater returns from smaller firms to compensate for less marketability and liquidity of their securities. Duff & Phelps discusses the nature of the small-size phenomenon, providing an indication of the magnitude of the size premium based on several measures of size. In discussing "Size as a Predictor of Equity Returns," Duff & Phelps states:

> The size effect is based on the empirical observation that companies of smaller size are associated with greater risk and, therefore, have greater cost of capital [sic]. The "size" of a company is one of the most important risk elements to consider when developing cost of equity capital estimates for use in valuing a business simply because size has been shown to be a *predictor* of equity returns. In other words, there is a significant (negative) relationship between size and historical equity returns - as size

---

91 *See, e.g.,* Mario Levis, *The record on small companies: A review of the evidence,* Journal of Asset Management, March 2002.

92 Morningstar, Ibbotson SBBI 2013 Valuation Yearbook, at 109.

> *decreases*, returns tend to *increase*, and vice versa. (footnote omitted) (emphasis in original)[93]

Q. Are you aware of other studies regarding the existence of a size premium for regulated utilities?

A. Yes. A 2002 study by Thomas M. Zepp concludes that size premia do exist for smaller utilities. Developed in response to a 1993 study by Annie Wong, the Zepp study focuses specifically on the utility industry and the effect of the size premium in a regulated environment. For example, one study reviewed by Zepp found that smaller water utilities had a cost of equity that, on average, was 99 basis points higher than the average cost of equity for the larger water utilities, and the result was statistically significant at the 90.00 percent level.[94] Zepp concludes that "to the extent water utilities are representative of all utilities, there is support for smaller utilities being more risky than larger ones."[95]

Q. Is it appropriate to consider the risk associated with UES's small size even though it is a subsidiary of a larger entity?

A. Yes. The widely accepted "stand-alone" regulatory principle treats each utility subsidiary as its own company. Parent entities, like other investors, have capital constraints and must look at the attractiveness of the expected risk-adjusted return of each investment alternative in their capital budgeting process. The "opportunity cost" concept applies regardless of the source of the funding. When funding is provided by a parent entity, the

---

93 Duff & Phelps 2019 Cost of Capital Navigator, at Chapter 4-1.

94 Thomas M. Zepp, *Utility stocks and the size effect – revisited*, The Quarterly Review of Economics and Finance, 43 (2003), at 580-581.

95 Thomas M. Zepp, *Utility stocks and the size effect – revisited*, The Quarterly Review of Economics and Finance, 43 (2003), at 582.

return still must be sufficient to provide an incentive to allocate equity capital to the subsidiary or business unit rather than other internal or external investment opportunities. That is, the regulated subsidiary must compete for capital with all the parent company's affiliates, as well as with other, similarly situated utility companies. In that regard, investors value corporate entities on a sum-of-the-parts basis and expect each division within the parent company to provide an appropriate risk-adjusted return. Therefore, it is important that the authorized ROE reflects the risks and prospects of the regulated utility's operations and supports the regulated utility's financial integrity from a stand-alone perspective.

Q. How does UES compare in size to the proxy companies?

A. UES's electric utility operations are significantly smaller than the proxy companies. Exhibit JEN-8 estimates the implied market capitalization for UES. The implied market capitalization is calculated by applying the median market-to-book ratio for the proxy group of 1.79 to UES's implied total common equity of approximately $119.58 million.[96] The implied market capitalization based on that calculation is approximately $214.19 million, which is approximately 1.24 percent of the proxy group median market capitalization of approximately $17.25 billion. Even if we were to compare the Company's parent, Unitil Corporation, to the proxy group, Unitil Corporation's market

96 The equity value of UES is estimated based on the approximate value of the proposed rate base and recommended capital structure.

capitalization of approximately $630 million[97] is less than half of the smallest proxy company, Otter Tail Corporation.

Q. How did you estimate the size premium for UES?

A. In its *Cost of Capital Navigator*, Duff & Phelps presents its calculation of the size premium for deciles of market capitalizations relative to the S&P 500 Index. An additional estimate of the size premium associated with UES, therefore, is the difference in the Ibbotson size risk premia for the proxy group median market capitalization relative to the implied market capitalization for UES.

As shown on Exhibit JEN-8, according to recent market data, the median market capitalization of the proxy group is approximately $17.25 billion, which corresponds to the 2nd decile of Ibbotson market capitalization data. Based on the Duff & Phelps analysis, that decile corresponds to a size premium of 0.49 percent (or 49 basis points). The implied market capitalization for UES is approximately $214.19 million, which falls within the 9th decile and corresponds to a size premium of 2.29 percent (or 229 basis points). The difference between those size premia is 180 basis points (2.29 percent – 0.49 percent).

97 Source: S&P Global Market Intelligence. 30-trading day average market capitalization as of February 26, 2021. A market capitalization of $630 million places Unitil in Duff & Phelps' 8th size decile as shown in Exhibit JEN-8.

Q. Have you considered the comparatively small size of UES in your estimated return on common equity?

A. Yes. While I have quantified the small size effect, rather than proposing a specific premium, I have considered the relatively small size of UES in determining where, within a reasonable range of returns, UES's required ROE appropriately falls.

B. Revenue Decoupling

Q. Please briefly describe the Company's proposed revenue decoupling mechanisms.

A. As explained in the direct testimony of Timothy S. Lyons, the Company is proposing a full revenue decoupling mechanism that reconciles monthly actual and authorized revenue per customer by rate class, in which revenue shortfalls (*i.e.*, actual revenue per customer is less than the authorized revenue per customer) during the measurement period will result in a surcharge for the customers. Conversely, revenue surpluses (*i.e.*, actual revenue per customer is greater than authorized revenue per customer) during the measurement period will result in a credit or refund to the customers. The monthly variances will be aggregated over 12 months to develop the revenue decoupling adjustment and will be allocated to each rate class.

Q. How common are revenue stabilization and cost recovery mechanisms within the industry in general?

A. There is little question that revenue stabilization and cost recovery structures have become increasingly common. The increased interest in such mechanisms has generally resulted from the growing cost of maintaining system reliability, coupled with flat or declining sales volume brought on by energy efficiency. Adjustment mechanisms to recover fuel costs, purchased power expenses, energy efficiency and demand-side program costs, new plant investment, and other expenses are common.[98] In addition, full or partial decoupling mechanisms have been implemented by electric utilities in 35 states.[99] Although the specific form of the Company's proposed mechanisms may be unique, the adoption and implementation of alternative regulation mechanisms in general is quite common and has become an increasingly visible issue to investors.

Q. Are cost recovery and revenue stabilization mechanisms common among the proxy companies?

A. Yes, they are. Exhibit JEN-9 provides a summary of revenue stabilization mechanisms and cost trackers currently in effect at each electric utility subsidiary of the proxy companies. As Exhibit JEN-9 demonstrates, all the proxy companies employ cost recovery mechanisms similar to those in place at the Company. Nearly all the proxy companies' operating subsidiaries recover fuel, as well as energy efficiency costs through a cost recovery mechanism. As to decoupling mechanisms, 16 of the 24 proxy companies have either a full or partial decoupling mechanism in place in at least one operating subsidiary. Exhibit JEN-9 also includes a summary of the alternative regulation and incentive plans currently in effect at the proxy companies, including

98 *See*, Exhibit JEN-9.

99 *See, e.g.*, *Adjustment Clauses: A State-by-State Overview*, Regulatory Research Associates Regulatory Focus, November 12, 2019; *Alternative ratemaking plans in the U.S.*, Regulatory Research Associates Regulatory Focus, April 16, 2020; ACEEE, State and Local Policy Database, Utility Business Model, https://database.aceee.org/state/utility-business-model.

formula-based rate plans, which provide comprehensive adjustment mechanisms that automatically adjust rates if the earned return is above or below an authorized range.

Q. Are you aware of any studies that have addressed the relationship between revenue decoupling mechanisms, generally, and the Cost of Capital?

A. Yes. In March 2014, The Brattle Group ("Brattle") published a study addressing the effect of revenue decoupling structures on the Cost of Capital for electric utilities.[100] In its report, which extended a prior analysis focused on natural gas distribution utilities, Brattle pointed out that although decoupling structures may affect revenue, net income still can vary.[101] Brattle further noted that the distinction between diversifiable and non-diversifiable risk is important to equity investors, and the relationship between revenue decoupling and the Cost of Equity should be examined in that context. To that point, Brattle noted that although reductions in total risk may be important to bondholders, only reductions in non-diversifiable business risk would justify a reduction to the ROE.[102] In November 2016, the Brattle study was updated based on data through the fourth quarter of 2015.[103]

---

[100] *See*, The Brattle Group, *The Impact of Revenue Decoupling on the Cost of Capital for Electric Utilities: An Empirical Investigation, Prepared for The Energy Foundation, March 20, 2014.*

[101] *Ibid*. at 7.

[102] *Ibid*. at 8.

[103] *See*, The Brattle Group, *Effect on the Cost of Capital of Innovative Ratemaking that Relaxes the Linkage between Revenue and kWh Sales – An Updated Empirical Investigation of the Electric Industry*, November 2016. Also available at http://files.brattle.com/files/5711_effect_on_the_cost_of_capital_of_ratemaking_that_relaxes_the_linkage_between_revenue_and_kwh_sales.pdf.

Brattle's empirical analysis examined the relationship between decoupling and the After-Tax Weighted Average Cost of Capital for a group of electric utilities that had implemented decoupling structures in various jurisdictions throughout the United States. As with Brattle's 2014 study, the updated study found no statistically significant link between the Cost of Capital and revenue decoupling structures.[104]

In addition, Dr. Richard A. Michelfelder, together with Dylan W. D'Ascendis and Pauline M. Ahern, examined the relationship between decoupling and the Cost of Equity among electric, gas, and water utilities. Using the generalized consumption asset pricing model, they found decoupling to have no statistically significant effect on investor perceived risk, and the Cost of Equity.[105]

Q. How have you reflected that information in your assessment of the Company's Cost of Equity?

A. First, my analyses and conclusions recognize that developing the Cost of Equity necessarily is a comparative assessment. As such, even if it were the case that revenue stabilization mechanisms mitigate "risk," they only would affect the Cost of Equity if: (1) the effect of the mechanism was to reduce risk below the levels faced by the subject company's peers in the proxy group; and (2) investors knowingly reduced their return requirements for the Company as a direct consequence of the mechanisms. The first

[104] *Ibid.*

[105] *See*, Dr. Richard A. Michelfelder, Pauline M. Ahern, Dylan W. D'Ascendis, *Decoupling impact and public utility conservation investment*, Energy Policy 130 (2019) 311-319.

analytical step, therefore, is to understand whether revenue stabilization mechanisms are in place at the proxy companies.

The question of the extent to which revenue stabilization mechanisms are in place at comparable companies is addressed in Exhibit JEN-9. As noted earlier, a majority of the 24 proxy companies have a decoupling mechanism in place in at least one jurisdiction. Some proxy group operating companies that do not have a revenue decoupling mechanism have other mechanisms such as a formula rate plan that adjusts revenue annually to a target ROE. Because revenue stabilization mechanisms are common among electric distribution utilities, there is no evidence that the Company is less risky than its peers. Lastly, as discussed above, multiple studies have shown no statistically significant link between the Cost of Capital and revenue decoupling structures.

Q. In your opinion, is a reduction in the Cost of Equity in connection with the Company's proposed revenue decoupling mechanism warranted?

A. No. While the proposed decoupling mechanism would support UES's financial integrity, approval of the Company's proposed decoupling mechanism simply renders it more comparable to its peers. Because the Cost of Equity is a comparative exercise, to the extent decoupling mechanisms reduce a utility's risk, any risk-reducing effects are already reflected in the proxy group and, therefore, in the analytical results that underlie my recommended ROE range. Consequently, no adjustment to UES's ROE is warranted as a result of its proposed decoupling mechanism.

V. CAPITAL STRUCTURE

Q. What capital structure is UES requesting?

A. As explained in the direct testimony of Company witness Todd Diggins, UES is requesting its actual capital structure consisting of 52.91 percent common equity, 0.10 percent preferred stock equity, 46.99 percent long-term debt, and 0.00 percent short-term debt[106] is reasonable and should be used for ratemaking purposes for UES.

Q. How does the capital structure affect the Cost of Equity?

A. The capital structure relates to financial risk, which represents the risk that a company may not have adequate cash flows to meet its financial obligations and is a function of the percentage of debt (or financial leverage) in its capital structure. In that regard, as the percentage of debt in the capital structure increases, so do the fixed obligations for the repayment of that debt. Consequently, as the degree of financial leverage increases, the risk of financial distress (*i.e.*, financial risk) also increases. In essence, even if two firms face the same business risks, a company with meaningfully higher levels of debt in its capital structure is likely to have a higher cost of both debt and equity. Since the capital structure can affect the subject company's overall level of risk, it is an important consideration in establishing a just and reasonable rate of return. The higher the proportion of senior capital in the capital structure, the higher the financial risk that must be factored into the Cost of Equity.

106 *See,* Schedules RevReq-5 and RevReq-5-1.

Q. Is there support for the proposition that capital structure is a key consideration in establishing an appropriate ROE?

A. Yes. The Supreme Court and various utility commissions have long recognized the role of capital structure in the development of a just and reasonable rate of return for a regulated utility. In particular, a utility's leverage, or debt ratio, has been explicitly recognized as an important element in determining a just and reasonable rate of return:

> Although the determination of whether bonds or stocks should be issued is for management, the matter of debt ratio is not exclusively within its province. Debt ratio substantially affects the manner and cost of obtaining new capital. It is therefore an important factor in the rate of return and must necessarily be considered by and come within the authority of the body charged by law with the duty of fixing a just and reasonable rate of return.[107]

Perhaps ultimate authority for balancing the issues of cost and financial integrity is found in the Supreme Court's statement in *Hope*:

> The rate-making process under the Act, *i.e.*, the fixing of 'just and reasonable rates,' involves a balancing of the investor and the consumer interests.[108]

As the U.S. Court of Appeals, District of Columbia Circuit found in *Communications Satellite Corp. et. al. v. FCC*:

> The equity investor's stake is made less secure as the Company's debt rises, but the consumer rate-payer's burden is alleviated.[109]

---

[107] *New England Telephone & Telegraph Co. v. State*, 98 N.H. 211, 220, 97 AM213, 220 (1953), citing *New England Tel. & Tel. Co. v. Department of Pub. Util., (Mass.)*, 97 N.E. 2d 509, 514 (1951); *Petitions of New England Tel. & Tel. Co.*, 80 A2d 671, at 6 (1951).

[108] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S., at 603 (1944).

[109] *Communications Satellite Corp. v. Federal Communications Commission and United States of America*, 611 F.2d 883, at 19 (1977).

Consequently, the principles of fairness and reasonableness with respect to the allowed Return on Equity and capital structure are considered at both the federal and state levels. Additionally, Dr. Morin states:

> [t]he mix of debt and equity employed in computing the weighted average cost of capital influences the return required by debt and equity capital suppliers. For example, increasing the proportion of low-cost debt financing lowers the overall cost of capital but increases the financial risk of the company to the detriment of shareholders who require a higher return in compensation for the increased risk. As the utility employs relatively more debt capital, the low-cost advantage of debt may be more than offset by the increased cost of equity.[110]

Q. How did you assess the reasonableness of UES's requested capital structure with respect to the proxy group?

A. The proxy group has been selected to reflect comparable companies in terms of financial, business, and regulatory risks. Therefore, it is appropriate to compare the capital structures of the utility operating companies held by the proxy companies to that of the subject company in order to assess whether the requested capital structure is consistent with industry standards for companies with commensurate risk profiles.

Q. Please describe your analysis of UES's requested capital structure relative to industry practice.

A. As a measure of industry practice, I calculated the average capital structure for each of the electric utility operating companies held by the proxy companies over the last five fiscal quarters and the last eight fiscal quarters. As shown in Exhibit JEN-10, the proxy group average capital structure over those two averaging periods includes approximately

---

110 Roger A. Morin, Ph.D., New Regulatory Finance, at 25 (2006).

53.10 percent common equity, 46.70 percent long-term debt, and 0.20 percent preferred equity. The common equity ratio ranges from approximately 48.00 percent to 60.00 percent. Based on that review, the requested capital structure is consistent with actual capital structures in place at the proxy companies.

Q. What is the basis for using average capital components rather than a point-in-time measurement?

A. Measuring the capital components at a particular point in time can skew the capital structure by the specific circumstances of a particular period. Therefore, it is more appropriate to normalize the relative relationship between the components over a period of time.

Q. Is there a generally accepted approach to developing the appropriate capital structure for a regulated electric utility?

A. Yes, there are several generally accepted approaches to developing the appropriate capital structure. The reasonableness of the approach depends on the nature and circumstances of the subject company. Regardless of the approach taken, however, it is important that the capital structure enable the subject company to maintain its financial integrity, thereby enabling access to capital at competitive rates under a variety of economic and financial market conditions. Therefore, I conclude the requested capital structure of 52.91 percent common equity, 0.10 percent preferred stock equity, 46.99 percent long-term debt, and 0.00 percent short-term debt is reasonable for ratemaking purposes in this proceeding and should be approved.

VI. SUMMARY AND CONCLUSION

Q. What is your conclusion regarding UES's Cost of Equity and capital structure?

A. As discussed throughout my Direct Testimony, it is important to consider a variety of quantitative and qualitative information in reviewing analytical results and arriving at ROE determinations. Based on my review of the results from three commonly used analytical approaches, I conclude an ROE in the range of 9.90 percent to 10.50 percent represents the range of equity investors' required return for investment in electric utilities similar to UES in today's volatile capital market environment. Within that range, I conclude that an ROE of 10.20 percent represents the Cost of Equity for UES. That conclusion is a conservative estimate, particularly when UES's small size relative to the proxy companies is also considered.

As to the capital structure, I conclude that a capital structure consisting of 52.91 percent common equity, 0.10 percent preferred stock equity, 46.99 percent long-term debt, and 0.00 percent short-term debt is consistent with capital structures in place at the proxy group and, therefore, is reasonable for ratemaking purposes.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

JENNIFER E. NELSON
Assistant Vice President

Ms. Nelson has nearly thirteen years of experience in the energy industry, spanning the oil, natural gas, electric, and renewable energy segments. She has provided expert witness testimony for electric and natural gas utilities regarding the cost of capital and alternative ratemaking proposals. In her time as a consultant, Ms. Nelson has provided research and analysis on a variety of utility regulatory matters including ratemaking and regulatory policy, integrated resource planning, renewable power contracts, natural gas pipeline development, and natural gas utility supply planning issues. Ms. Nelson has extensive experience performing statistical analyses, developing economic and financial models, and providing policy analyses and recommendations.

Prior to joining Concentric, Ms. Nelson was a Director at ScottMadden, Inc. Prior to that Ms. Nelson was a managing consultant at Sussex Economic Advisors, LLC, and was formerly a staff economist at the Massachusetts Department of Public Utilities and a petroleum economist for the State of Alaska. Ms. Nelson holds a Master of Science degree in Resource and Applied Economics from the University of Alaska and a Bachelor of Science degree in Business Economics from Bentley College.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2021 – present)
Assistant Vice President

ScottMadden Management Consultants (2016 – 2021)
Director

Sussex Economic Advisors, LLC (2013 – 2016)
Managing Consultant

Massachusetts Department of Public Utilities (2011 – 2013)
Economist, Electric Power Division

State of Alaska Department of Revenue (2007 – 2010)
Petroleum Economist

EDUCATION

University of Alaska
Master of Science, Resource and Applied Economics

Bentley College
Bachelor of Science, Business Economics
Graduated *magna cum laude*

REPRESENTATIVE PROJECT EXPERIENCE

Cost of Capital

- Submitted expert testimony on behalf of an electric utility before the Arkansas Public Service Commission, the New Mexico Public Regulation Commission, and the Public Utilities Commission of Texas regarding the cost of capital.
- Submitted expert testimony on behalf of a natural gas utility before the Public Service Commission of West Virginia regarding the cost of capital.
- Submitted expert testimony on behalf of a water utility before the Kentucky Public Service Commission regarding the appropriate capital structure and cost of debt.
- Supported expert testimony regarding the cost of capital before numerous state utility regulatory commissions and the FERC on behalf of electric and natural gas utilities through state and company-specific research and analysis, financial analysis and modeling, and testimony development.

Alternative Ratemaking Mechanisms

- Submitted expert testimony on behalf of a water utility before the Arkansas Public Service Commission regarding the utility's proposed Formula Rate Plan.
- Co-sponsored expert testimony on behalf of a natural gas utility before the Maine Public Utilities Commission regarding the utility's proposed capital investment cost recovery mechanism.
- Supported expert testimony and performed research and analysis on alternative ratemaking frameworks.

Resource and Supply Planning

- Supported expert testimony on the reasonableness of utility resource supply portfolio decisions.
- Assisted in a benchmarking analysis on behalf of a Northeast natural gas utility regarding its supply planning standards and design day demand forecast process.
- Supported the development of a New Hampshire electric utility's Integrated Resource Plan filed with the New Hampshire Public Utility Commission.
- Performed research and financial analysis to evaluate the benefits, costs, and policy options associated with natural gas expansion by Massachusetts natural gas utilities as part of a prepared report for the Massachusetts Department of Energy Resources.

- Developed a dynamic natural gas demand forecast model for in-state use for the State of Alaska, which included forecasting demand from both existing and anticipated natural gas utilities, power consumption, and large commercial operations.
- Conducted research and prepared analyses for a natural gas pipeline Open Season.

Other Regulatory Financial Issues

- Supported expert testimony on the appropriate level of remuneration associated with electric utilities' long-term contract for wind power through financial analysis and modeling, and testimony development.
- Provided research and analytical support estimating financial damages incurred as a result of construction delays for an electric transmission company.
- Prepared a Feasibility Study for an electric cooperative utility supporting a utility-owned solar project.

Mergers & Acquisitions

- Performed buy-side benchmarking and regulatory analysis for a utility acquisition.

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Member, Society of Utility and Regulatory Financial Analysts

AVAILABLE UPON REQUEST

Extensive client and project listings, and specific references.

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Arkansas Public Service Commission				
Liberty Utilities (Pine Bluff Water)	10/18	Liberty Utilities (Pine Bluff Water)	18-027-U	Sponsored testimony supporting Liberty Utility's proposed Formula Rate Plan and tariff
Entergy Arkansas, LLC	11/20	Entergy Arkansas, LLC	16-036-FR	Sponsored testimony evaluating the Return on Equity included in Rider FRP
Kentucky Public Service Commission				
Bluegrass Water Utility Operating Company, LLC	09/20	Bluegrass Water Utility Operating Company, LLC	2020-290	Capital Structure and Cost of Long-Term Debt
Maine Public Utilities Commission				
Unitil Corporation	06/19	Northern Utilities, Inc.	19-00092	Co-sponsored testimony supporting Northern Utilities proposed CIRA capital tracking mechanism
New Mexico Public Regulation Commission				
El Paso Electric Company	07/20	El Paso Electric Company	20-00104-UT	Cost of Capital
Public Utilities Commission of Texas				
Sharyland Utilities L.L.C.	12/20	Sharyland Utilities L.L.C.	51611	Cost of Capital
Public Service Commission of West Virginia				
Hope Gas, Inc. d/b/a Dominion Energy West Virginia	11/20	Hope Gas, Inc. d/b/a Dominion Energy West Virginia	20-0746-G-42T	Cost of Capital

Constant Growth Discounted Cash Flow Model with Half Year Growth Adjustment
30 Day Average Stock Price

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Average Stock Price	Dividend Yield	Expected Dividend Yield	Zacks Earnings Growth	First Call Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.52	$64.82	3.89%	4.00%	NA	7.00%	4.50%	5.75%	8.48%	9.75%	11.02%
Alliant Energy Corporation	LNT	$1.61	$48.74	3.30%	3.40%	5.80%	5.70%	5.50%	5.67%	8.89%	9.06%	9.20%
Ameren Corporation	AEE	$2.20	$73.02	3.01%	3.11%	6.80%	6.60%	6.00%	6.47%	9.10%	9.58%	9.92%
American Electric Power Company, Inc.	AEP	$2.96	$79.89	3.70%	3.81%	5.80%	6.00%	6.00%	5.93%	9.61%	9.75%	9.82%
Avista Corporation	AVA	$1.69	$38.74	4.36%	4.45%	5.40%	6.00%	1.00%	4.13%	5.38%	8.59%	10.49%
CMS Energy Corporation	CMS	$1.74	$56.89	3.06%	3.17%	6.90%	7.26%	7.50%	7.22%	10.06%	10.39%	10.67%
Consolidated Edison, Inc.	ED	$3.10	$69.79	4.44%	4.50%	2.00%	2.95%	2.50%	2.48%	6.49%	6.98%	7.46%
DTE Energy Company	DTE	$4.34	$121.26	3.58%	3.69%	5.70%	6.05%	6.00%	5.92%	9.38%	9.60%	9.74%
Duke Energy Corporation	DUK	$3.86	$91.03	4.24%	4.35%	5.20%	4.99%	5.00%	5.06%	9.34%	9.41%	9.55%
Entergy Corporation	ETR	$3.80	$93.80	4.05%	4.14%	5.20%	5.15%	3.00%	4.45%	7.11%	8.59%	9.36%
Evergy, Inc	EVRG	$2.14	$54.07	3.96%	4.09%	6.10%	5.90%	7.50%	6.50%	9.97%	10.59%	11.61%
Eversource Energy	ES	$2.41	$85.74	2.81%	2.91%	6.80%	7.05%	6.50%	6.78%	9.40%	9.69%	9.96%
Hawaiian Electric Industries, Inc.	HE	$1.36	$34.26	3.97%	4.00%	2.50%	1.30%	1.50%	1.77%	5.30%	5.77%	6.52%
IDACORP, Inc.	IDA	$2.84	$88.22	3.22%	3.27%	2.60%	2.60%	4.50%	3.23%	5.86%	6.50%	7.79%
NextEra Energy, Inc.	NEE	$1.54	$81.31	1.89%	1.98%	7.80%	8.63%	10.50%	8.98%	9.77%	10.96%	12.49%
NorthWestern Corporation	NWE	$2.48	$56.85	4.36%	4.45%	5.30%	4.66%	2.50%	4.15%	6.92%	8.61%	9.78%
OGE Energy Corp.	OGE	$1.61	$31.16	5.17%	5.24%	3.60%	2.10%	3.00%	2.90%	7.32%	8.14%	8.86%
Otter Tail Corporation	OTTR	$1.56	$41.44	3.76%	3.91%	NA	9.00%	6.50%	7.75%	10.39%	11.66%	12.93%
Pinnacle West Capital Corporation	PNW	$3.32	$76.37	4.35%	4.43%	3.50%	3.50%	4.50%	3.83%	7.92%	8.26%	8.95%
Portland General Electric Company	POR	$1.63	$42.42	3.84%	4.04%	13.40%	13.40%	4.00%	10.27%	7.92%	14.31%	17.50%
Public Service Enterprise Group Incorporated	PEG	$2.04	$57.85	3.53%	3.59%	3.00%	3.00%	5.00%	3.67%	6.58%	7.26%	8.61%
Southern Company	SO	$2.56	$59.65	4.29%	4.38%	5.00%	4.36%	3.50%	4.29%	7.87%	8.67%	9.40%
WEC Energy Group, Inc.	WEC	$2.71	$85.87	3.16%	3.25%	6.10%	6.14%	6.00%	6.08%	9.25%	9.33%	9.39%
Xcel Energy Inc.	XEL	$1.83	$62.91	2.91%	3.00%	6.10%	6.20%	6.00%	6.10%	9.00%	9.10%	9.20%
Proxy Group Mean				3.70%	3.80%	5.48%	5.65%	4.94%	5.39%	8.22%	9.19%	10.01%
Proxy Group Median				3.80%	3.95%	5.55%	5.95%	5.00%	5.71%	8.68%	9.21%	9.64%
Average of the Proxy Group Mean and Median										8.45%	9.20%	9.83%

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service, equals indicated number of trading day average as of 02/26/2021
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model with Half Year Growth Adjustment
90 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.52	$60.44	4.17%	4.29%	NA	7.00%	4.50%	5.75%	8.76%	10.04%	11.32%
Alliant Energy Corporation	LNT	$1.61	$51.66	3.12%	3.21%	5.80%	5.70%	5.50%	5.67%	8.70%	8.87%	9.01%
Ameren Corporation	AEE	$2.20	$77.18	2.85%	2.94%	6.80%	6.60%	6.00%	6.47%	8.94%	9.41%	9.75%
American Electric Power Company, Inc.	AEP	$2.96	$83.64	3.54%	3.64%	5.80%	6.00%	6.00%	5.93%	9.44%	9.58%	9.65%
Avista Corporation	AVA	$1.69	$37.95	4.45%	4.54%	5.40%	6.00%	1.00%	4.13%	5.47%	8.68%	10.59%
CMS Energy Corporation	CMS	$1.74	$60.09	2.90%	3.00%	6.90%	7.26%	7.50%	7.22%	9.90%	10.22%	10.50%
Consolidated Edison, Inc.	ED	$3.10	$73.86	4.20%	4.25%	2.00%	2.95%	2.50%	2.48%	6.24%	6.73%	7.21%
DTE Energy Company	DTE	$4.34	$123.45	3.52%	3.62%	5.70%	6.05%	6.00%	5.92%	9.32%	9.54%	9.67%
Duke Energy Corporation	DUK	$3.86	$91.85	4.20%	4.31%	5.20%	4.99%	5.00%	5.06%	9.30%	9.37%	9.51%
Entergy Corporation	ETR	$3.80	$100.56	3.78%	3.86%	5.20%	5.15%	3.00%	4.45%	6.84%	8.31%	9.08%
Evergy, Inc	EVRG	$2.14	$54.73	3.91%	4.04%	6.10%	5.90%	7.50%	6.50%	9.93%	10.54%	11.56%
Eversource Energy	ES	$2.41	$87.65	2.75%	2.84%	6.80%	7.05%	6.50%	6.78%	9.34%	9.63%	9.90%
Hawaiian Electric Industries, Inc.	HE	$1.36	$35.07	3.88%	3.91%	2.50%	1.30%	1.50%	1.77%	5.20%	5.68%	6.43%
IDACORP, Inc.	IDA	$2.84	$90.68	3.13%	3.18%	2.60%	2.60%	4.50%	3.23%	5.77%	6.42%	7.70%
NextEra Energy, Inc.	NEE	$1.54	$77.41	1.99%	2.08%	7.80%	8.63%	10.50%	8.98%	9.87%	11.06%	12.59%
NorthWestern Corporation	NWE	$2.48	$56.75	4.37%	4.46%	5.30%	4.66%	2.50%	4.15%	6.92%	8.61%	9.79%
OGE Energy Corp.	OGE	$1.61	$31.98	5.04%	5.11%	3.60%	2.10%	3.00%	2.90%	7.19%	8.01%	8.73%
Otter Tail Corporation	OTTR	$1.56	$41.45	3.76%	3.91%	NA	9.00%	6.50%	7.75%	10.39%	11.66%	12.93%
Pinnacle West Capital Corporation	PNW	$3.32	$80.26	4.14%	4.22%	3.50%	3.50%	4.50%	3.83%	7.71%	8.05%	8.73%
Portland General Electric Company	POR	$1.63	$41.89	3.89%	4.09%	13.40%	13.40%	4.00%	10.27%	7.97%	14.36%	17.55%
Public Service Enterprise Group Incorporated	PEG	$2.04	$58.10	3.51%	3.58%	3.00%	3.00%	5.00%	3.67%	6.56%	7.24%	8.60%
Southern Company	SO	$2.56	$60.30	4.25%	4.34%	5.00%	4.36%	3.50%	4.29%	7.82%	8.62%	9.35%
WEC Energy Group, Inc.	WEC	$2.71	$92.47	2.93%	3.02%	6.10%	6.14%	6.00%	6.08%	9.02%	9.10%	9.16%
Xcel Energy Inc.	XEL	$1.83	$66.68	2.74%	2.83%	6.10%	6.20%	6.00%	6.10%	8.83%	8.93%	9.03%
Proxy Group Mean				3.63%	3.72%	5.48%	5.65%	4.94%	5.39%	8.14%	9.11%	9.93%
Proxy Group Median				3.77%	3.89%	5.55%	5.95%	5.00%	5.71%	8.73%	9.01%	9.58%
Average of the Proxy Group Mean and Median										8.44%	9.06%	9.75%

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service, equals indicated number of trading day average as of 02/26/2021
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model with Half Year Growth Adjustment
180 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.52	$57.93	4.35%	4.47%	NA	7.00%	4.50%	5.75%	8.95%	10.22%	11.50%
Alliant Energy Corporation	LNT	$1.61	$51.75	3.11%	3.20%	5.80%	5.70%	5.50%	5.67%	8.70%	8.87%	9.00%
Ameren Corporation	AEE	$2.20	$77.41	2.84%	2.93%	6.80%	6.60%	6.00%	6.47%	8.93%	9.40%	9.74%
American Electric Power Company, Inc.	AEP	$2.96	$83.28	3.55%	3.66%	5.80%	6.00%	6.00%	5.93%	9.46%	9.59%	9.66%
Avista Corporation	AVA	$1.69	$36.97	4.57%	4.67%	5.40%	6.00%	1.00%	4.13%	5.59%	8.80%	10.71%
CMS Energy Corporation	CMS	$1.74	$60.58	2.87%	2.98%	6.90%	7.26%	7.50%	7.22%	9.87%	10.20%	10.48%
Consolidated Edison, Inc.	ED	$3.10	$74.28	4.17%	4.23%	2.00%	2.95%	2.50%	2.48%	6.22%	6.71%	7.18%
DTE Energy Company	DTE	$4.34	$118.63	3.66%	3.77%	5.70%	6.05%	6.00%	5.92%	9.46%	9.68%	9.82%
Duke Energy Corporation	DUK	$3.86	$87.84	4.39%	4.51%	5.20%	4.99%	5.00%	5.06%	9.49%	9.57%	9.71%
Entergy Corporation	ETR	$3.80	$99.92	3.80%	3.89%	5.20%	5.15%	3.00%	4.45%	6.86%	8.34%	9.10%
Evergy, Inc	EVRG	$2.14	$55.41	3.86%	3.99%	6.10%	5.90%	7.50%	6.50%	9.88%	10.49%	11.51%
Eversource Energy	ES	$2.41	$86.82	2.78%	2.87%	6.80%	7.05%	6.50%	6.78%	9.37%	9.65%	9.92%
Hawaiian Electric Industries, Inc.	HE	$1.36	$35.10	3.87%	3.91%	2.50%	1.30%	1.50%	1.77%	5.20%	5.68%	6.42%
IDACORP, Inc.	IDA	$2.84	$89.14	3.19%	3.24%	2.60%	2.60%	4.50%	3.23%	5.83%	6.47%	7.76%
NextEra Energy, Inc.	NEE	$1.54	$72.94	2.11%	2.21%	7.80%	8.63%	10.50%	8.98%	9.99%	11.18%	12.72%
NorthWestern Corporation	NWE	$2.48	$54.93	4.51%	4.61%	5.30%	4.66%	2.50%	4.15%	7.07%	8.76%	9.93%
OGE Energy Corp.	OGE	$1.61	$31.66	5.08%	5.16%	3.60%	2.10%	3.00%	2.90%	7.24%	8.06%	8.78%
Otter Tail Corporation	OTTR	$1.56	$39.99	3.90%	4.05%	NA	9.00%	6.50%	7.75%	10.53%	11.80%	13.08%
Pinnacle West Capital Corporation	PNW	$3.32	$78.49	4.23%	4.31%	3.50%	3.50%	4.50%	3.83%	7.80%	8.14%	8.82%
Portland General Electric Company	POR	$1.63	$40.99	3.98%	4.18%	13.40%	13.40%	4.00%	10.27%	8.06%	14.45%	17.64%
Public Service Enterprise Group Incorporated	PEG	$2.04	$55.53	3.67%	3.74%	3.00%	3.00%	5.00%	3.67%	6.73%	7.41%	8.77%
Southern Company	SO	$2.56	$57.21	4.48%	4.57%	5.00%	4.36%	3.50%	4.29%	8.05%	8.86%	9.59%
WEC Energy Group, Inc.	WEC	$2.71	$92.85	2.92%	3.01%	6.10%	6.14%	6.00%	6.08%	9.01%	9.09%	9.15%
Xcel Energy Inc.	XEL	$1.83	$67.37	2.72%	2.80%	6.10%	6.20%	6.00%	6.10%	8.80%	8.90%	9.00%
Proxy Group Mean				3.69%	3.79%	5.48%	5.65%	4.94%	5.39%	8.21%	9.18%	10.00%
Proxy Group Median				3.83%	3.90%	5.55%	5.95%	5.00%	5.71%	8.75%	8.99%	9.68%
Average of the Proxy Group Mean and Median										8.48%	9.09%	9.84%

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service, equals indicated number of trading day average as of 02/26/2021
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Quarterly Discounted Cash Flow Model
30 Day Average Stock Price

Company	Ticker	[1] Dividend 1	[2] Dividend 2	[3] Dividend 3	[4] Dividend 4	[5] Expected Dividend 1	[6] Expected Dividend 2	[7] Expected Dividend 3	[8] Expected Dividend 4	[9] Stock Price	[10] Zacks Earnings Growth	[11] First Call Earnings Growth	[12] Value Line Earnings Growth	[13] Average Earnings Growth	[14] Low ROE	[15] Mean ROE	[16] High ROE
ALLETE, Inc.	ALE	$0.63	$0.62	$0.62	$0.62	$0.67	$0.65	$0.65	$0.65	$64.82	NA	7.00%	4.50%	5.75%	8.63%	9.95%	11.27%
Alliant Energy Corporation	LNT	$0.40	$0.38	$0.38	$0.38	$0.43	$0.40	$0.40	$0.40	$48.74	5.80%	5.70%	5.50%	5.67%	8.95%	9.12%	9.26%
Ameren Corporation	AEE	$0.55	$0.52	$0.50	$0.50	$0.59	$0.55	$0.53	$0.53	$73.02	6.80%	6.60%	6.00%	6.47%	9.09%	9.57%	9.92%
American Electric Power Company, Inc.	AEP	$0.74	$0.74	$0.70	$0.70	$0.78	$0.78	$0.74	$0.74	$79.89	5.80%	6.00%	6.00%	5.93%	9.75%	9.89%	9.96%
Avista Corporation	AVA	$0.42	$0.41	$0.41	$0.41	$0.44	$0.42	$0.42	$0.42	$38.74	5.40%	6.00%	1.00%	4.13%	5.35%	8.68%	10.66%
CMS Energy Corporation	CMS	$0.44	$0.41	$0.41	$0.41	$0.47	$0.44	$0.44	$0.44	$56.89	6.90%	7.26%	7.50%	7.22%	10.13%	10.47%	10.76%
Consolidated Edison, Inc.	ED	$0.78	$0.77	$0.77	$0.77	$0.79	$0.78	$0.78	$0.78	$69.79	2.00%	2.95%	2.50%	2.48%	6.60%	7.11%	7.61%
DTE Energy Company	DTE	$1.09	$1.09	$1.01	$1.01	$1.15	$1.15	$1.07	$1.07	$121.26	5.70%	6.05%	6.00%	5.92%	9.49%	9.71%	9.85%
Duke Energy Corporation	DUK	$0.97	$0.97	$0.97	$0.95	$1.01	$1.01	$1.01	$0.99	$91.03	5.20%	4.99%	5.00%	5.06%	9.58%	9.65%	9.80%
Entergy Corporation	ETR	$0.95	$0.95	$0.93	$0.93	$0.99	$0.99	$0.97	$0.97	$93.80	5.20%	5.15%	3.00%	4.45%	7.24%	8.77%	9.57%
Evergy, Inc	EVRG	$0.54	$0.54	$0.51	$0.51	$0.57	$0.57	$0.54	$0.54	$54.07	6.10%	5.90%	7.50%	6.50%	10.13%	10.76%	11.82%
Eversource Energy	ES	$0.60	$0.57	$0.57	$0.57	$0.64	$0.61	$0.61	$0.61	$85.74	6.80%	7.05%	6.50%	6.78%	9.46%	9.76%	10.04%
Hawaiian Electric Industries, Inc.	HE	$0.34	$0.33	$0.33	$0.33	$0.35	$0.34	$0.34	$0.34	$34.26	2.50%	1.30%	1.50%	1.77%	5.31%	5.80%	6.58%
IDACORP, Inc.	IDA	$0.71	$0.71	$0.67	$0.67	$0.73	$0.73	$0.69	$0.69	$88.22	2.60%	2.60%	4.50%	3.23%	5.88%	6.54%	7.87%
NextEra Energy, Inc.	NEE	$0.39	$0.35	$0.35	$0.35	$0.42	$0.38	$0.38	$0.38	$81.31	7.80%	8.63%	10.50%	8.98%	9.77%	10.98%	12.54%
NorthWestern Corporation	NWE	$0.62	$0.60	$0.60	$0.60	$0.65	$0.62	$0.62	$0.62	$56.85	5.30%	4.66%	2.50%	4.15%	6.98%	8.73%	9.95%
OGE Energy Corp.	OGE	$0.40	$0.40	$0.40	$0.39	$0.41	$0.41	$0.41	$0.40	$31.16	3.60%	2.10%	3.00%	2.90%	7.47%	8.33%	9.08%
Otter Tail Corporation	OTTR	$0.39	$0.37	$0.37	$0.37	$0.42	$0.40	$0.40	$0.40	$41.44	NA	9.00%	6.50%	7.75%	10.51%	11.82%	13.14%
Pinnacle West Capital Corporation	PNW	$0.83	$0.83	$0.78	$0.78	$0.86	$0.86	$0.81	$0.81	$76.37	3.50%	3.50%	4.50%	3.83%	8.00%	8.36%	9.06%
Portland General Electric Company	POR	$0.41	$0.41	$0.41	$0.39	$0.45	$0.45	$0.45	$0.42	$42.42	13.40%	13.40%	4.00%	10.27%	8.06%	14.67%	17.98%
Public Service Enterprise Group Incorporated	PEG	$0.51	$0.49	$0.49	$0.49	$0.53	$0.51	$0.51	$0.51	$57.85	3.00%	3.00%	5.00%	3.67%	6.61%	7.31%	8.71%
Southern Company	SO	$0.64	$0.64	$0.64	$0.64	$0.67	$0.67	$0.67	$0.67	$59.65	5.00%	4.36%	3.50%	4.29%	8.07%	8.91%	9.67%
WEC Energy Group, Inc.	WEC	$0.68	$0.63	$0.63	$0.63	$0.72	$0.67	$0.67	$0.67	$85.87	6.10%	6.14%	6.00%	6.08%	9.29%	9.37%	9.44%
Xcel Energy Inc.	XEL	$0.46	$0.43	$0.43	$0.43	$0.49	$0.46	$0.46	$0.46	$62.91	6.10%	6.20%	6.00%	6.10%	9.04%	9.15%	9.25%
Proxy Group Mean											5.48%	5.65%	4.94%	5.39%	8.31%	9.31%	10.16%
Proxy Group Median											5.55%	5.95%	5.00%	5.71%	8.79%	9.26%	9.83%
Average of the Proxy Group Mean and Median															8.55%	9.29%	9.99%

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service
[3] Source: Bloomberg Professional Service
[4] Source: Bloomberg Professional Service
[5] Equals Col. [1] x (1 + Col. [13])
[6] Equals Col. [2] x (1 + Col. [13])
[7] Equals Col. [3] x (1 + Col. [13])
[8] Equals Col. [4] x (1 + Col. [13])
[9] Source: Bloomberg Professional Service, equals indicated number of trading day average as of 02/26/2021
[10] Source: Zacks
[11] Source: Yahoo! Finance
[12] Source: Value Line
[13] Equals Average (Cols. [10], [11], [12])
[14] Implied Low DCF
[15] Implied Mean DCF
[16] Implied High DCF

Quarterly Discounted Cash Flow Model
90 Day Average Stock Price

Company	Ticker	[1] Dividend 1	[2] Dividend 2	[3] Dividend 3	[4] Dividend 4	[5] Expected Dividend 1	[6] Expected Dividend 2	[7] Expected Dividend 3	[8] Expected Dividend 4	[9] Stock Price	[10] Zacks Earnings Growth	[11] First Call Earnings Growth	[12] Value Line Earnings Growth	[13] Average Earnings Growth	[14] Low ROE	[15] Mean ROE	[16] High ROE
ALLETE, Inc.	ALE	$0.63	$0.62	$0.62	$0.62	$0.67	$0.65	$0.65	$0.65	$60.44	NA	7.00%	4.50%	5.75%	8.93%	10.26%	11.58%
Alliant Energy Corporation	LNT	$0.40	$0.38	$0.38	$0.38	$0.43	$0.40	$0.40	$0.40	$51.66	5.80%	5.70%	5.50%	5.67%	8.75%	8.93%	9.07%
Ameren Corporation	AEE	$0.55	$0.52	$0.50	$0.50	$0.59	$0.55	$0.53	$0.53	$77.18	6.80%	6.60%	6.00%	6.47%	8.92%	9.40%	9.75%
American Electric Power Company, Inc.	AEP	$0.74	$0.74	$0.70	$0.70	$0.78	$0.78	$0.74	$0.74	$83.64	5.80%	6.00%	6.00%	5.93%	9.57%	9.71%	9.78%
Avista Corporation	AVA	$0.42	$0.41	$0.41	$0.41	$0.44	$0.42	$0.42	$0.42	$37.95	5.40%	6.00%	1.00%	4.13%	5.45%	8.77%	10.76%
CMS Energy Corporation	CMS	$0.44	$0.41	$0.41	$0.41	$0.47	$0.44	$0.44	$0.44	$60.09	6.90%	7.26%	7.50%	7.22%	9.96%	10.29%	10.58%
Consolidated Edison, Inc.	ED	$0.78	$0.77	$0.77	$0.77	$0.79	$0.78	$0.78	$0.78	$73.86	2.00%	2.95%	2.50%	2.48%	6.34%	6.85%	7.35%
DTE Energy Company	DTE	$1.09	$1.09	$1.01	$1.01	$1.15	$1.15	$1.07	$1.07	$123.45	5.70%	6.05%	6.00%	5.92%	9.42%	9.65%	9.79%
Duke Energy Corporation	DUK	$0.97	$0.97	$0.97	$0.95	$1.01	$1.01	$1.01	$0.99	$91.85	5.20%	4.99%	5.00%	5.06%	9.53%	9.61%	9.76%
Entergy Corporation	ETR	$0.95	$0.95	$0.93	$0.93	$0.99	$0.99	$0.97	$0.97	$100.56	5.20%	5.15%	3.00%	4.45%	6.95%	8.48%	9.27%
Evergy, Inc	EVRG	$0.54	$0.54	$0.51	$0.51	$0.57	$0.57	$0.54	$0.54	$54.73	6.10%	5.90%	7.50%	6.50%	10.08%	10.71%	11.76%
Eversource Energy	ES	$0.60	$0.57	$0.57	$0.57	$0.64	$0.61	$0.61	$0.61	$87.65	6.80%	7.05%	6.50%	6.78%	9.40%	9.69%	9.97%
Hawaiian Electric Industries, Inc.	HE	$0.34	$0.33	$0.33	$0.33	$0.35	$0.34	$0.34	$0.34	$35.07	2.50%	1.30%	1.50%	1.77%	5.22%	5.71%	6.48%
IDACORP, Inc.	IDA	$0.71	$0.71	$0.67	$0.67	$0.73	$0.73	$0.69	$0.69	$90.68	2.60%	2.60%	4.50%	3.23%	5.79%	6.45%	7.77%
NextEra Energy, Inc.	NEE	$0.39	$0.35	$0.35	$0.35	$0.42	$0.38	$0.38	$0.38	$77.41	7.80%	8.63%	10.50%	8.98%	9.87%	11.08%	12.65%
NorthWestern Corporation	NWE	$0.62	$0.60	$0.60	$0.60	$0.65	$0.62	$0.62	$0.62	$56.75	5.30%	4.66%	2.50%	4.15%	6.98%	8.74%	9.96%
OGE Energy Corp.	OGE	$0.40	$0.40	$0.40	$0.39	$0.41	$0.41	$0.41	$0.40	$31.98	3.60%	2.10%	3.00%	2.90%	7.33%	8.19%	8.94%
Otter Tail Corporation	OTTR	$0.39	$0.37	$0.37	$0.37	$0.42	$0.40	$0.40	$0.40	$41.45	NA	9.00%	6.50%	7.75%	10.50%	11.82%	13.14%
Pinnacle West Capital Corporation	PNW	$0.83	$0.83	$0.78	$0.78	$0.86	$0.86	$0.81	$0.81	$80.26	3.50%	3.50%	4.50%	3.83%	7.78%	8.13%	8.84%
Portland General Electric Company	POR	$0.41	$0.41	$0.41	$0.39	$0.45	$0.45	$0.45	$0.42	$41.89	13.40%	13.40%	4.00%	10.27%	8.11%	14.73%	18.04%
Public Service Enterprise Group Incorporated	PEG	$0.51	$0.49	$0.49	$0.49	$0.53	$0.51	$0.51	$0.51	$58.10	3.00%	3.00%	5.00%	3.67%	6.60%	7.30%	8.69%
Southern Company	SO	$0.64	$0.64	$0.64	$0.64	$0.67	$0.67	$0.67	$0.67	$60.30	5.00%	4.36%	3.50%	4.29%	8.02%	8.86%	9.62%
WEC Energy Group, Inc.	WEC	$0.68	$0.63	$0.63	$0.63	$0.72	$0.67	$0.67	$0.67	$92.47	6.10%	6.14%	6.00%	6.08%	9.05%	9.14%	9.20%
Xcel Energy Inc.	XEL	$0.46	$0.43	$0.43	$0.43	$0.49	$0.46	$0.46	$0.46	$66.68	6.10%	6.20%	6.00%	6.10%	8.87%	8.97%	9.08%
Proxy Group Mean											5.48%	5.65%	4.94%	5.39%	8.23%	9.23%	10.08%
Proxy Group Median											5.55%	5.95%	5.00%	5.71%	8.81%	9.05%	9.75%
Average of the Proxy Group Mean and Median															8.52%	9.14%	9.91%

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service
[3] Source: Bloomberg Professional Service
[4] Source: Bloomberg Professional Service
[5] Equals Col. [1] x (1 + Col. [13])
[6] Equals Col. [2] x (1 + Col. [13])
[7] Equals Col. [3] x (1 + Col. [13])
[8] Equals Col. [4] x (1 + Col. [13])
[9] Source: Bloomberg Professional Service, equals indicated number of trading day average as of 02/26/2021
[10] Source: Zacks
[11] Source: Yahoo! Finance
[12] Source: Value Line
[13] Equals Average (Cols. [10], [11], [12])
[14] Implied Low DCF
[15] Implied Mean DCF
[16] Implied High DCF

Quarterly Discounted Cash Flow Model
180 Day Average Stock Price

Company	Ticker	[1] Dividend 1	[2] Dividend 2	[3] Dividend 3	[4] Dividend 4	[5] Expected Dividend 1	[6] Expected Dividend 2	[7] Expected Dividend 3	[8] Expected Dividend 4	[9] Stock Price	[10] Zacks Earnings Growth	[11] First Call Earnings Growth	[12] Value Line Earnings Growth	[13] Average Earnings Growth	[14] Low ROE	[15] Mean ROE	[16] High ROE
ALLETE, Inc.	ALE	$0.63	$0.62	$0.62	$0.62	$0.67	$0.65	$0.65	$0.65	$57.93	NA	7.00%	4.50%	5.75%	9.13%	10.46%	11.78%
Alliant Energy Corporation	LNT	$0.40	$0.38	$0.38	$0.38	$0.43	$0.40	$0.40	$0.40	$51.75	5.80%	5.70%	5.50%	5.67%	8.75%	8.92%	9.06%
Ameren Corporation	AEE	$0.55	$0.52	$0.50	$0.50	$0.59	$0.55	$0.53	$0.53	$77.41	6.80%	6.60%	6.00%	6.47%	8.91%	9.39%	9.74%
American Electric Power Company, Inc.	AEP	$0.74	$0.74	$0.70	$0.70	$0.78	$0.78	$0.74	$0.74	$83.28	5.80%	6.00%	6.00%	5.93%	9.59%	9.73%	9.80%
Avista Corporation	AVA	$0.42	$0.41	$0.41	$0.41	$0.44	$0.42	$0.42	$0.42	$36.97	5.40%	6.00%	1.00%	4.13%	5.57%	8.90%	10.89%
CMS Energy Corporation	CMS	$0.44	$0.41	$0.41	$0.41	$0.47	$0.44	$0.44	$0.44	$60.58	6.90%	7.26%	7.50%	7.22%	9.93%	10.27%	10.56%
Consolidated Edison, Inc.	ED	$0.78	$0.77	$0.77	$0.77	$0.79	$0.78	$0.78	$0.78	$74.28	2.00%	2.95%	2.50%	2.48%	6.31%	6.83%	7.32%
DTE Energy Company	DTE	$1.09	$1.09	$1.01	$1.01	$1.15	$1.15	$1.07	$1.07	$118.63	5.70%	6.05%	6.00%	5.92%	9.57%	9.80%	9.94%
Duke Energy Corporation	DUK	$0.97	$0.97	$0.97	$0.95	$1.01	$1.01	$1.01	$0.99	$87.84	5.20%	4.99%	5.00%	5.06%	9.74%	9.82%	9.97%
Entergy Corporation	ETR	$0.95	$0.95	$0.93	$0.93	$0.99	$0.99	$0.97	$0.97	$99.92	5.20%	5.15%	3.00%	4.45%	6.98%	8.50%	9.29%
Evergy, Inc	EVRG	$0.54	$0.54	$0.51	$0.51	$0.57	$0.57	$0.54	$0.54	$55.41	6.10%	5.90%	7.50%	6.50%	10.02%	10.66%	11.71%
Eversource Energy	ES	$0.60	$0.57	$0.57	$0.57	$0.64	$0.61	$0.61	$0.61	$86.82	6.80%	7.05%	6.50%	6.78%	9.43%	9.72%	10.00%
Hawaiian Electric Industries, Inc.	HE	$0.34	$0.33	$0.33	$0.33	$0.35	$0.34	$0.34	$0.34	$35.10	2.50%	1.30%	1.50%	1.77%	5.21%	5.70%	6.48%
IDACORP, Inc.	IDA	$0.71	$0.71	$0.67	$0.67	$0.73	$0.73	$0.69	$0.69	$89.14	2.60%	2.60%	4.50%	3.23%	5.85%	6.51%	7.83%
NextEra Energy, Inc.	NEE	$0.39	$0.35	$0.35	$0.35	$0.42	$0.38	$0.38	$0.38	$72.94	7.80%	8.63%	10.50%	8.98%	10.00%	11.21%	12.78%
NorthWestern Corporation	NWE	$0.62	$0.60	$0.60	$0.60	$0.65	$0.62	$0.62	$0.62	$54.93	5.30%	4.66%	2.50%	4.15%	7.14%	8.89%	10.11%
OGE Energy Corp.	OGE	$0.40	$0.40	$0.40	$0.39	$0.41	$0.41	$0.41	$0.40	$31.66	3.60%	2.10%	3.00%	2.90%	7.38%	8.24%	8.99%
Otter Tail Corporation	OTTR	$0.39	$0.37	$0.37	$0.37	$0.42	$0.40	$0.40	$0.40	$39.99	NA	9.00%	6.50%	7.75%	10.65%	11.97%	13.29%
Pinnacle West Capital Corporation	PNW	$0.83	$0.83	$0.78	$0.78	$0.86	$0.86	$0.81	$0.81	$78.49	3.50%	3.50%	4.50%	3.83%	7.88%	8.23%	8.94%
Portland General Electric Company	POR	$0.41	$0.41	$0.41	$0.39	$0.45	$0.45	$0.45	$0.42	$40.99	13.40%	13.40%	4.00%	10.27%	8.20%	14.83%	18.14%
Public Service Enterprise Group Incorporated	PEG	$0.51	$0.49	$0.49	$0.49	$0.53	$0.51	$0.51	$0.51	$55.53	3.00%	3.00%	5.00%	3.67%	6.77%	7.47%	8.87%
Southern Company	SO	$0.64	$0.64	$0.64	$0.64	$0.67	$0.67	$0.67	$0.67	$57.21	5.00%	4.36%	3.50%	4.29%	8.27%	9.11%	9.87%
WEC Energy Group, Inc.	WEC	$0.68	$0.63	$0.63	$0.63	$0.72	$0.67	$0.67	$0.67	$92.85	6.10%	6.14%	6.00%	6.08%	9.04%	9.12%	9.18%
Xcel Energy Inc.	XEL	$0.46	$0.43	$0.43	$0.43	$0.49	$0.46	$0.46	$0.46	$67.37	6.10%	6.20%	6.00%	6.10%	8.84%	8.94%	9.05%
Proxy Group Mean											5.48%	5.65%	4.94%	5.39%	8.30%	9.30%	10.15%
Proxy Group Median											5.55%	5.95%	5.00%	5.71%	8.79%	9.12%	9.83%
Average of the Proxy Group Mean and Median															8.55%	9.21%	9.99%

Notes:
[1] Source: Bloomberg Professional Service
[2] Source: Bloomberg Professional Service
[3] Source: Bloomberg Professional Service
[4] Source: Bloomberg Professional Service
[5] Equals Col. [1] x (1 + Col. [13])
[6] Equals Col. [2] x (1 + Col. [13])
[7] Equals Col. [3] x (1 + Col. [13])
[8] Equals Col. [4] x (1 + Col. [13])
[9] Source: Bloomberg Professional Service, equals indicated number of trading day average as of 02/26/2021
[10] Source: Zacks
[11] Source: Yahoo! Finance
[12] Source: Value Line
[13] Equals Average (Cols. [10], [11], [12])
[14] Implied Low DCF
[15] Implied Mean DCF
[16] Implied High DCF

Expected Market Return
Market DCF Method Based - Bloomberg

[1]
S&P 500 Est. Required Market Return
16.35%

Company	Ticker	[2] Market Capitalization	[3] Weight in Index	[4] Estimated Dividend Yield	[5] Long-Term Growth Est.	[6] DCF Result	[7] Weighted DCF Result
Agilent Technologies Inc	A	37,278.88	0.11%	0.62%	7.60%	8.24%	0.0093%
American Airlines Group Inc	AAL	13,394.81	0.04%	0.00%	50.30%	50.30%	0.0205%
Advance Auto Parts Inc	AAP	10,506.84	0.03%	0.61%	13.84%	14.50%	0.0046%
Apple Inc	AAPL	2,035,724.52	6.19%	0.70%	10.38%	11.11%	0.6878%
AbbVie Inc	ABBV	190,256.09	0.58%	4.77%	1.67%	6.48%	0.0375%
AmerisourceBergen Corp	ABC	20,720.36	0.06%	1.75%	6.78%	8.58%	0.0054%
ABIOMED Inc	ABMD	14,679.71	0.04%	0.00%	16.00%	16.00%	0.0071%
Abbott Laboratories	ABT	212,193.79	0.65%	1.35%	14.64%	16.09%	0.1038%
Accenture PLC	ACN	166,119.57	0.51%	1.40%	10.85%	12.32%	0.0622%
Adobe Inc	ADBE	220,044.03	0.67%	0.00%	15.98%	15.98%	0.1069%
Analog Devices Inc	ADI	57,481.02	0.17%	1.72%	8.95%	10.75%	0.0188%
Archer-Daniels-Midland Co	ADM	31,595.07	0.10%	2.61%	2.10%	4.74%	0.0046%
Automatic Data Processing Inc	ADP	74,470.16	0.23%	2.14%	11.33%	13.60%	0.0308%
Autodesk Inc	ADSK	60,689.48	0.18%	0.00%	24.97%	24.97%	0.0461%
Ameren Corp	AEE	17,370.66	0.05%	3.02%	7.16%	10.29%	0.0054%
American Electric Power Co Inc	AEP	37,170.82	0.11%	3.99%	6.52%	10.64%	0.0120%
AES Corp/The	AES	17,675.14	0.05%	2.30%	7.07%	9.44%	0.0051%
Aflac Inc	AFL	32,976.44	0.10%	2.76%	1.55%	4.33%	0.0043%
American International Group Inc	AIG	38,007.55	0.12%	3.02%	20.10%	23.43%	0.0271%
Assurant Inc	AIZ	7,134.81	N/A	2.53%	N/A	N/A	N/A
Arthur J Gallagher & Co	AJG	23,210.05	0.07%	1.58%	23.99%	25.76%	0.0182%
Akamai Technologies Inc	AKAM	15,424.32	0.05%	0.00%	11.25%	11.25%	0.0053%
Albemarle Corp	ALB	18,335.79	0.06%	0.98%	15.75%	16.81%	0.0094%
Align Technology Inc	ALGN	44,876.96	0.14%	0.00%	16.77%	16.77%	0.0229%
Alaska Air Group Inc	ALK	8,077.20	0.02%	0.00%	191.70%	191.70%	0.0471%
Allstate Corp/The	ALL	32,286.31	0.10%	2.26%	28.45%	31.03%	0.0305%
Allegion plc	ALLE	9,869.86	0.03%	1.30%	7.59%	8.94%	0.0027%
Alexion Pharmaceuticals Inc	ALXN	33,560.97	0.10%	0.00%	13.45%	13.45%	0.0137%
Applied Materials Inc	AMAT	108,458.33	0.33%	0.77%	13.38%	14.20%	0.0468%
Amcor PLC	AMCR	17,088.04	0.05%	4.32%	8.66%	13.17%	0.0068%
Advanced Micro Devices Inc	AMD	102,365.27	0.31%	0.00%	27.07%	27.07%	0.0842%
AMETEK Inc	AME	27,199.62	0.08%	0.63%	8.55%	9.21%	0.0076%
Amgen Inc	AMGN	129,906.23	N/A	3.09%	N/A	N/A	N/A
Ameriprise Financial Inc	AMP	25,830.28	0.08%	1.99%	47.95%	50.42%	0.0396%
American Tower Corp	AMT	96,044.81	0.29%	2.46%	14.33%	16.96%	0.0495%
Amazon.com Inc	AMZN	1,557,490.50	4.74%	0.00%	31.50%	31.50%	1.4915%
Arista Networks Inc	ANET	21,360.63	0.06%	0.00%	11.30%	11.30%	0.0073%
ANSYS Inc	ANSS	29,581.48	0.09%	0.00%	12.05%	12.05%	0.0108%
Anthem Inc	ANTM	74,252.96	0.23%	1.39%	12.21%	13.68%	0.0309%
Aon PLC	AON	51,458.90	0.16%	0.81%	13.10%	13.96%	0.0218%
A O Smith Corp	AOS	9,605.00	0.03%	1.83%	10.00%	11.92%	0.0035%
Apache Corp	APA	7,455.20	0.02%	0.51%	145.95%	146.83%	0.0333%
Air Products and Chemicals Inc	APD	56,562.80	0.17%	2.28%	11.43%	13.84%	0.0238%
Amphenol Corp	APH	37,650.80	0.11%	0.92%	11.52%	12.49%	0.0143%
Aptiv PLC	APTV	40,460.60	0.12%	0.24%	11.19%	11.44%	0.0141%
Alexandria Real Estate Equities Inc	ARE	21,828.46	0.07%	2.78%	5.74%	8.60%	0.0057%
Atmos Energy Corp	ATO	10,843.68	0.03%	2.93%	7.16%	10.20%	0.0034%
Activision Blizzard Inc	ATVI	74,074.23	0.23%	0.48%	10.75%	11.26%	0.0254%
AvalonBay Communities Inc	AVB	24,521.96	0.07%	3.73%	2.16%	5.93%	0.0044%
Broadcom Inc	AVGO	191,813.31	0.58%	3.04%	7.70%	10.85%	0.0633%
Avery Dennison Corp	AVY	14,550.14	0.04%	1.43%	4.77%	6.23%	0.0028%
American Water Works Co Inc	AWK	25,742.60	N/A	1.65%	N/A	N/A	N/A
American Express Co	AXP	108,963.97	0.33%	1.31%	17.21%	18.63%	0.0617%
AutoZone Inc	AZO	26,398.74	0.08%	0.00%	8.64%	8.64%	0.0069%
Boeing Co/The	BA	123,601.16	N/A	0.00%	N/A	N/A	N/A
Bank of America Corp	BAC	299,657.88	0.91%	2.18%	14.30%	16.64%	0.1516%
Baxter International Inc	BAX	39,241.52	0.12%	1.36%	9.66%	11.08%	0.0132%
Best Buy Co Inc	BBY	25,985.12	0.08%	2.56%	9.85%	12.53%	0.0099%
Becton Dickinson and Co	BDX	70,068.54	0.21%	1.58%	9.54%	11.19%	0.0238%
Franklin Resources Inc	BEN	13,226.42	0.04%	4.28%	11.00%	15.52%	0.0062%
Brown-Forman Corp	BF/B	33,413.01	0.10%	0.99%	5.57%	6.58%	0.0067%
Biogen Inc	BIIB	41,569.37	N/A	0.00%	N/A	N/A	N/A
Bio-Rad Laboratories Inc	BIO	17,526.07	0.05%	0.00%	28.75%	28.75%	0.0153%
Bank of New York Mellon Corp/The	BK	37,047.48	0.11%	3.07%	8.65%	11.85%	0.0133%
Booking Holdings Inc	BKNG	95,379.95	0.29%	0.00%	10.23%	10.23%	0.0297%
Baker Hughes Co	BKR	25,468.89	0.08%	3.03%	16.20%	19.47%	0.0151%
BlackRock Inc	BLK	106,675.55	0.32%	2.21%	10.85%	13.18%	0.0428%
Ball Corp	BLL	28,001.77	0.09%	0.69%	5.00%	5.71%	0.0049%
Bristol-Myers Squibb Co	BMY	137,408.34	0.42%	3.14%	30.61%	34.22%	0.1430%
Broadridge Financial Solutions Inc	BR	16,500.17	0.05%	1.60%	10.70%	12.38%	0.0062%
Berkshire Hathaway Inc	BRK/B	566,407.11	N/A	0.00%	N/A	N/A	N/A
Boston Scientific Corp	BSX	54,957.69	0.17%	0.00%	11.94%	11.94%	0.0200%
BorgWarner Inc	BWA	10,755.95	0.03%	1.54%	10.71%	12.32%	0.0040%
Boston Properties Inc	BXP	15,445.01	0.05%	3.98%	3.34%	7.39%	0.0035%
Citigroup Inc	C	137,159.50	0.42%	3.17%	16.12%	19.54%	0.0815%
Conagra Brands Inc	CAG	16,577.48	0.05%	2.88%	7.30%	10.28%	0.0052%
Cardinal Health Inc	CAH	15,129.75	0.05%	3.80%	5.01%	8.91%	0.0041%
Carrier Global Corp	CARR	31,752.36	N/A	1.20%	N/A	N/A	N/A
Caterpillar Inc	CAT	117,720.19	0.36%	2.06%	11.50%	13.67%	0.0489%
Chubb Ltd	CB	73,197.57	0.22%	1.96%	9.30%	11.35%	0.0253%
Cboe Global Markets Inc	CBOE	10,609.51	0.03%	1.74%	5.62%	7.41%	0.0024%
CBRE Group Inc	CBRE	25,428.20	0.08%	0.00%	8.45%	8.45%	0.0065%
Crown Castle International Corp	CCI	67,176.82	0.20%	3.46%	20.80%	24.62%	0.0503%
Carnival Corp	CCL	28,314.16	0.09%	0.00%	10.00%	10.00%	0.0086%

Company	Ticker	[2] Market Capitalization	[3] Weight in Index	[4] Estimated Dividend Yield	[5] Long-Term Growth Est.	[6] DCF Result	[7] Weighted DCF Result
Cadence Design Systems Inc	CDNS	39,360.44	0.12%	0.24%	11.35%	11.60%	0.0139%
CDW Corp/DE	CDW	22,433.42	0.07%	1.07%	13.10%	14.24%	0.0097%
Celanese Corp	CE	15,859.82	0.05%	1.96%	5.52%	7.53%	0.0036%
Cerner Corp	CERN	21,177.19	0.06%	0.68%	11.06%	11.78%	0.0076%
CF Industries Holdings Inc	CF	9,697.15	0.03%	2.68%	14.35%	17.22%	0.0051%
Citizens Financial Group Inc	CFG	18,466.62	0.06%	3.63%	2.21%	5.88%	0.0033%
Church & Dwight Co Inc	CHD	19,299.54	0.06%	1.20%	7.97%	9.21%	0.0054%
CH Robinson Worldwide Inc	CHRW	12,157.13	0.04%	2.36%	8.95%	11.42%	0.0042%
Charter Communications Inc	CHTR	138,260.49	0.42%	0.01%	33.86%	33.88%	0.1424%
Cigna Corp	CI	73,852.39	0.22%	0.65%	10.81%	11.50%	0.0258%
Cincinnati Financial Corp	CINF	15,776.83	N/A	2.50%	N/A	N/A	N/A
Colgate-Palmolive Co	CL	63,811.91	0.19%	2.51%	6.35%	8.94%	0.0173%
Clorox Co/The	CLX	22,774.51	0.07%	2.48%	5.72%	8.27%	0.0057%
Comerica Inc	CMA	9,485.38	0.03%	4.01%	6.43%	10.56%	0.0030%
Comcast Corp	CMCSA	241,492.19	0.73%	1.90%	12.33%	14.35%	0.1054%
CME Group Inc	CME	71,690.42	0.22%	3.20%	6.09%	9.38%	0.0205%
Chipotle Mexican Grill Inc	CMG	40,583.74	0.12%	0.00%	22.35%	22.35%	0.0276%
Cummins Inc	CMI	37,386.90	0.11%	2.15%	9.10%	11.34%	0.0129%
CMS Energy Corp	CMS	15,634.72	0.05%	3.22%	7.03%	10.37%	0.0049%
Centene Corp	CNC	34,046.46	0.10%	0.00%	12.85%	12.85%	0.0133%
CenterPoint Energy Inc	CNP	10,591.28	0.03%	3.23%	1.85%	5.11%	0.0016%
Capital One Financial Corp	COF	55,195.66	0.17%	1.32%	20.25%	21.70%	0.0364%
Cabot Oil & Gas Corp	COG	7,377.71	0.02%	2.57%	2.77%	5.37%	0.0012%
Cooper Cos Inc/The	COO	18,975.63	0.06%	0.01%	10.83%	10.85%	0.0063%
ConocoPhillips	COP	70,459.75	0.21%	3.33%	-43.62%	-41.02%	-0.0879%
Costco Wholesale Corp	COST	146,618.18	0.45%	1.22%	10.00%	11.28%	0.0503%
Campbell Soup Co	CPB	13,777.94	0.04%	3.22%	8.37%	11.73%	0.0049%
Copart Inc	CPRT	25,796.36	0.08%	0.00%	10.00%	10.00%	0.0078%
salesforce.com Inc	CRM	198,689.52	0.60%	0.00%	17.97%	17.97%	0.1085%
Cisco Systems Inc/Delaware	CSCO	189,431.52	0.58%	3.23%	5.53%	8.85%	0.0510%
CSX Corp	CSX	69,807.34	0.21%	1.21%	9.39%	10.66%	0.0226%
Cintas Corp	CTAS	34,065.42	0.10%	1.31%	9.76%	11.13%	0.0115%
Catalent Inc	CTLT	19,356.46	0.06%	0.00%	15.82%	15.82%	0.0093%
Cognizant Technology Solutions Corp	CTSH	38,989.54	0.12%	1.28%	10.04%	11.38%	0.0135%
Corteva Inc	CTVA	33,567.13	0.10%	1.16%	11.58%	12.81%	0.0131%
Citrix Systems Inc	CTXS	16,425.49	0.05%	1.11%	10.30%	11.47%	0.0057%
CVS Health Corp	CVS	89,342.61	0.27%	2.95%	6.45%	9.49%	0.0258%
Chevron Corp	CVX	192,637.68	0.59%	5.23%	21.96%	27.76%	0.1626%
Dominion Energy Inc	D	55,041.88	0.17%	3.68%	7.02%	10.82%	0.0181%
Delta Air Lines Inc	DAL	30,592.75	0.09%	0.09%	388.45%	388.70%	0.3615%
DuPont de Nemours Inc	DD	37,838.42	0.12%	1.73%	5.27%	7.05%	0.0081%
Deere & Co	DE	109,427.80	0.33%	0.90%	24.31%	25.32%	0.0842%
Discover Financial Services	DFS	28,850.49	0.09%	1.88%	23.82%	25.93%	0.0227%
Dollar General Corp	DG	46,302.72	0.14%	0.75%	15.30%	16.10%	0.0227%
Quest Diagnostics Inc	DGX	15,426.04	0.05%	2.08%	-0.30%	1.78%	0.0008%
DR Horton Inc	DHI	27,957.75	0.08%	1.04%	14.44%	15.56%	0.0132%
Danaher Corp	DHR	156,449.90	0.48%	0.38%	11.55%	11.95%	0.0568%
Walt Disney Co/The	DIS	343,157.49	1.04%	0.29%	27.64%	27.97%	0.2918%
Discovery Inc	DISCA	31,998.32	0.10%	0.00%	4.67%	4.67%	0.0045%
DISH Network Corp	DISH	16,579.62	0.05%	0.00%	4.64%	4.64%	0.0023%
Digital Realty Trust Inc	DLR	38,847.51	0.12%	3.47%	11.90%	15.57%	0.0184%
Dollar Tree Inc	DLTR	23,095.87	0.07%	0.00%	10.92%	10.92%	0.0077%
Dover Corp	DOV	17,706.21	0.05%	1.65%	10.87%	12.61%	0.0068%
Dow Inc	DOW	43,955.91	0.13%	4.76%	19.31%	24.53%	0.0328%
Domino's Pizza Inc	DPZ	13,445.80	0.04%	1.06%	15.60%	16.75%	0.0068%
Duke Realty Corp	DRE	14,670.31	0.04%	2.60%	8.45%	11.16%	0.0050%
Darden Restaurants Inc	DRI	17,897.97	0.05%	1.03%	13.55%	14.65%	0.0080%
DTE Energy Co	DTE	22,614.61	0.07%	3.70%	5.17%	8.96%	0.0062%
Duke Energy Corp	DUK	65,818.71	0.20%	4.63%	4.55%	9.29%	0.0186%
DaVita Inc	DVA	11,173.02	0.03%	0.00%	15.52%	15.52%	0.0053%
Devon Energy Corp	DVN	14,498.57	0.04%	3.47%	0.48%	3.96%	0.0017%
DXC Technology Co	DXC	6,420.86	0.02%	0.63%	-1.83%	-1.20%	-0.0002%
DexCom Inc	DXCM	38,257.43	0.12%	0.00%	24.84%	24.84%	0.0289%
Electronic Arts Inc	EA	38,533.26	0.12%	0.10%	7.50%	7.60%	0.0089%
eBay Inc	EBAY	38,390.75	0.12%	1.28%	20.99%	22.41%	0.0262%
Ecolab Inc	ECL	59,845.55	0.18%	0.94%	15.40%	16.41%	0.0299%
Consolidated Edison Inc	ED	22,479.82	0.07%	4.77%	3.63%	8.49%	0.0058%
Equifax Inc	EFX	19,715.05	0.06%	0.98%	12.59%	13.63%	0.0082%
Edison International	EIX	20,477.51	0.06%	4.88%	4.17%	9.16%	0.0057%
Estee Lauder Cos Inc/The	EL	103,698.43	0.32%	0.71%	16.98%	17.75%	0.0560%
Eastman Chemical Co	EMN	14,844.27	0.05%	2.55%	6.45%	9.08%	0.0041%
Emerson Electric Co	EMR	51,542.55	0.16%	2.37%	9.88%	12.37%	0.0194%
Enphase Energy Inc	ENPH	22,715.49	0.07%	0.00%	37.68%	37.68%	0.0260%
EOG Resources Inc	EOG	37,674.86	0.11%	2.28%	-1.77%	0.49%	0.0006%
Equinix Inc	EQIX	57,888.89	0.18%	1.77%	21.95%	23.91%	0.0421%
Equity Residential	EQR	24,375.90	0.07%	3.71%	3.15%	6.92%	0.0051%
Eversource Energy	ES	27,261.91	0.08%	3.03%	7.65%	10.80%	0.0089%
Essex Property Trust Inc	ESS	16,559.95	0.05%	3.29%	3.99%	7.35%	0.0037%
Eaton Corp PLC	ETN	51,828.64	0.16%	2.34%	8.95%	11.39%	0.0179%
Entergy Corp	ETR	17,383.25	0.05%	4.47%	4.61%	9.19%	0.0049%
Etsy Inc	ETSY	27,774.06	0.08%	0.00%	31.00%	31.00%	0.0262%
Evergy Inc	EVRG	12,155.72	0.04%	4.03%	7.00%	11.17%	0.0041%
Edwards Lifesciences Corp	EW	51,897.52	0.16%	0.00%	14.50%	14.50%	0.0229%
Exelon Corp	EXC	37,593.69	0.11%	4.12%	4.76%	8.97%	0.0103%
Expeditors International of Washington I	EXPD	15,555.02	0.05%	1.18%	3.95%	5.16%	0.0024%
Expedia Group Inc	EXPE	23,162.19	0.07%	0.38%	6.97%	7.36%	0.0052%
Extra Space Storage Inc	EXR	16,511.70	0.05%	2.96%	2.86%	5.86%	0.0029%
Ford Motor Co	F	46,550.73	0.14%	1.07%	47.86%	49.18%	0.0696%
Diamondback Energy Inc	FANG	10,947.32	0.03%	2.21%	8.99%	11.30%	0.0038%
Fastenal Co	FAST	26,632.20	0.08%	2.35%	10.15%	12.62%	0.0102%
Facebook Inc	FB	733,616.73	2.23%	0.00%	20.97%	20.97%	0.4677%
Fortune Brands Home & Security Inc	FBHS	11,528.71	0.04%	1.22%	10.04%	11.32%	0.0040%
Freeport-McMoRan Inc	FCX	49,457.07	0.15%	0.78%	21.89%	22.76%	0.0342%
FedEx Corp	FDX	67,460.47	0.21%	1.05%	14.30%	15.42%	0.0316%
FirstEnergy Corp	FE	18,002.15	0.05%	4.73%	2.13%	6.90%	0.0038%
F5 Networks Inc	FFIV	11,712.42	0.04%	0.00%	14.82%	14.82%	0.0053%

Company	Ticker	[2] Market Capitalization	[3] Weight in Index	[4] Estimated Dividend Yield	[5] Long-Term Growth Est.	[6] DCF Result	[7] Weighted DCF Result
Fidelity National Information Services I	FIS	85,715.75	0.26%	1.10%	14.10%	15.28%	0.0398%
Fiserv Inc	FISV	77,235.59	0.23%	0.00%	17.40%	17.40%	0.0409%
Fifth Third Bancorp	FITB	24,725.64	0.08%	3.15%	20.95%	24.43%	0.0184%
FLIR Systems Inc	FLIR	7,008.13	N/A	1.36%	N/A	N/A	N/A
Flowserve Corp	FLS	4,820.21	0.01%	2.23%	7.05%	9.36%	0.0014%
FleetCor Technologies Inc	FLT	23,201.46	0.07%	0.00%	15.67%	15.67%	0.0111%
FMC Corp	FMC	13,153.97	0.04%	1.84%	9.75%	11.68%	0.0047%
Fox Corp	FOX	19,317.45	0.06%	1.47%	1.93%	3.41%	0.0020%
First Republic Bank/CA	FRC	28,657.17	0.09%	0.50%	13.21%	13.75%	0.0120%
Federal Realty Investment Trust	FRT	7,764.59	0.02%	4.21%	4.15%	8.45%	0.0020%
Fortinet Inc	FTNT	27,554.79	0.08%	0.00%	14.15%	14.15%	0.0119%
Fortive Corp	FTV	22,240.58	0.07%	0.45%	5.77%	6.23%	0.0042%
General Dynamics Corp	GD	46,795.69	0.14%	2.87%	6.65%	9.61%	0.0137%
General Electric Co	GE	109,949.99	0.33%	0.32%	47.03%	47.43%	0.1585%
Gilead Sciences Inc	GILD	77,154.82	N/A	4.42%	N/A	N/A	N/A
General Mills Inc	GIS	33,635.13	0.10%	3.68%	6.10%	9.89%	0.0101%
Globe Life Inc	GL	9,646.67	0.03%	0.85%	36.28%	37.28%	0.0109%
Corning Inc	GLW	29,382.39	0.09%	2.55%	14.26%	16.99%	0.0152%
General Motors Co	GM	73,962.06	0.22%	1.22%	13.01%	14.31%	0.0322%
Alphabet Inc	GOOG	1,368,283.31	4.16%	0.00%	18.28%	18.28%	0.7604%
Genuine Parts Co	GPC	15,212.96	0.05%	3.11%	5.83%	9.03%	0.0042%
Global Payments Inc	GPN	58,455.24	0.18%	0.37%	12.58%	12.96%	0.0230%
Gap Inc/The	GPS	9,332.03	0.03%	0.38%	17.80%	18.22%	0.0052%
Garmin Ltd	GRMN	23,758.68	0.07%	2.11%	7.13%	9.32%	0.0067%
Goldman Sachs Group Inc/The	GS	115,139.24	0.35%	1.64%	10.78%	12.51%	0.0438%
WW Grainger Inc	GWW	19,520.95	0.06%	1.71%	14.50%	16.34%	0.0097%
Halliburton Co	HAL	19,398.85	0.06%	0.95%	49.00%	50.18%	0.0296%
Hasbro Inc	HAS	12,871.23	0.04%	3.04%	11.79%	15.00%	0.0059%
Huntington Bancshares Inc/OH	HBAN	15,604.55	0.05%	3.97%	11.72%	15.92%	0.0076%
Hanesbrands Inc	HBI	6,170.36	0.02%	3.44%	4.35%	7.86%	0.0015%
HCA Healthcare Inc	HCA	58,476.01	0.18%	1.10%	11.08%	12.24%	0.0218%
Home Depot Inc/The	HD	278,129.05	0.85%	2.52%	10.53%	13.18%	0.1115%
Hess Corp	HES	20,122.78	0.06%	1.53%	35.91%	37.72%	0.0231%
HollyFrontier Corp	HFC	6,152.27	0.02%	3.71%	1.90%	5.64%	0.0011%
Hartford Financial Services Group Inc/Th	HIG	18,122.40	0.06%	2.76%	37.60%	40.88%	0.0225%
Huntington Ingalls Industries Inc	HII	7,092.12	0.02%	2.61%	27.25%	30.22%	0.0065%
Hilton Worldwide Holdings Inc	HLT	34,334.53	0.10%	0.04%	-4.51%	-4.47%	-0.0047%
Hologic Inc	HOLX	18,574.84	0.06%	0.00%	13.64%	13.64%	0.0077%
Honeywell International Inc	HON	140,734.66	0.43%	1.86%	9.50%	11.45%	0.0490%
Hewlett Packard Enterprise Co	HPE	18,941.04	0.06%	3.39%	14.46%	18.09%	0.0104%
HP Inc	HPQ	36,113.96	0.11%	2.74%	10.81%	13.69%	0.0150%
Hormel Foods Corp	HRL	25,036.00	0.08%	2.13%	5.10%	7.28%	0.0055%
Henry Schein Inc	HSIC	8,811.40	0.03%	0.00%	5.64%	5.64%	0.0015%
Host Hotels & Resorts Inc	HST	11,702.00	0.04%	0.16%	-7.40%	-7.25%	-0.0026%
Hershey Co/The	HSY	30,173.66	0.09%	2.26%	5.20%	7.51%	0.0069%
Humana Inc	HUM	48,922.43	0.15%	0.73%	12.21%	12.99%	0.0193%
Howmet Aerospace Inc	HWM	12,188.91	0.04%	0.28%	38.40%	38.74%	0.0144%
International Business Machines Corp	IBM	106,275.15	0.32%	5.70%	9.72%	15.69%	0.0507%
Intercontinental Exchange Inc	ICE	61,961.86	0.19%	1.18%	10.77%	12.02%	0.0226%
IDEXX Laboratories Inc	IDXX	44,436.08	0.14%	0.00%	15.76%	15.76%	0.0213%
IDEX Corp	IEX	14,811.40	0.05%	1.09%	13.83%	14.99%	0.0067%
International Flavors & Fragrances Inc	IFF	33,704.89	0.10%	2.25%	19.83%	22.31%	0.0229%
Illumina Inc	ILMN	64,109.92	0.19%	0.00%	28.36%	28.36%	0.0553%
Incyte Corp	INCY	17,292.89	0.05%	0.00%	32.20%	32.20%	0.0169%
IHS Markit Ltd	INFO	35,756.73	0.11%	0.52%	11.40%	11.95%	0.0130%
Intel Corp	INTC	246,949.14	0.75%	2.26%	5.24%	7.56%	0.0568%
Intuit Inc	INTU	106,835.89	0.32%	0.74%	15.80%	16.60%	0.0539%
International Paper Co	IP	19,518.26	0.06%	4.12%	3.10%	7.29%	0.0043%
Interpublic Group of Cos Inc/The	IPG	10,204.51	0.03%	3.18%	4.62%	7.88%	0.0024%
IPG Photonics Corp	IPGP	12,170.86	0.04%	0.00%	45.56%	45.56%	0.0169%
IQVIA Holdings Inc	IQV	36,967.25	0.11%	0.00%	18.04%	18.04%	0.0203%
Ingersoll Rand Inc	IR	19,354.16	0.06%	0.30%	15.10%	15.42%	0.0091%
Iron Mountain Inc	IRM	10,034.17	0.03%	7.15%	2.87%	10.12%	0.0031%
Intuitive Surgical Inc	ISRG	86,734.84	0.26%	0.00%	8.50%	8.50%	0.0224%
Gartner Inc	IT	15,884.71	0.05%	0.00%	13.50%	13.50%	0.0065%
Illinois Tool Works Inc	ITW	64,022.78	0.19%	2.21%	10.41%	12.74%	0.0248%
Invesco Ltd	IVZ	10,292.40	0.03%	2.84%	2.00%	4.87%	0.0015%
Jacobs Engineering Group Inc	J	14,970.32	0.05%	0.76%	12.19%	12.99%	0.0059%
JB Hunt Transport Services Inc	JBHT	15,524.89	0.05%	0.78%	17.23%	18.08%	0.0085%
Johnson Controls International plc	JCI	40,183.97	0.12%	1.94%	13.90%	15.98%	0.0195%
Jack Henry & Associates Inc	JKHY	11,292.91	0.03%	1.18%	12.80%	14.05%	0.0048%
Johnson & Johnson	JNJ	416,540.60	1.27%	2.68%	7.99%	10.77%	0.1365%
Juniper Networks Inc	JNPR	7,639.85	0.02%	3.51%	8.16%	11.82%	0.0027%
JPMorgan Chase & Co	JPM	449,090.20	1.37%	2.49%	5.87%	8.43%	0.1151%
Kellogg Co	K	19,849.37	0.06%	4.03%	3.66%	7.76%	0.0047%
KeyCorp	KEY	19,511.94	0.06%	3.77%	10.75%	14.72%	0.0087%
Keysight Technologies Inc	KEYS	26,334.68	0.08%	0.00%	10.41%	10.41%	0.0083%
Kraft Heinz Co/The	KHC	44,499.13	0.14%	4.41%	0.42%	4.84%	0.0065%
Kimco Realty Corp	KIM	7,926.62	0.02%	3.50%	4.57%	8.15%	0.0020%
KLA Corp	KLAC	47,952.65	0.15%	1.19%	9.75%	11.01%	0.0160%
Kimberly-Clark Corp	KMB	43,422.24	0.13%	3.52%	5.35%	8.96%	0.0118%
Kinder Morgan Inc	KMI	33,287.42	0.10%	7.33%	4.00%	11.48%	0.0116%
CarMax Inc	KMX	19,425.33	0.06%	0.00%	7.16%	7.16%	0.0042%
Coca-Cola Co/The	KO	211,113.18	0.64%	3.42%	5.80%	9.33%	0.0599%
Kroger Co/The	KR	24,522.99	0.07%	2.12%	7.50%	9.70%	0.0072%
Kansas City Southern	KSU	19,290.63	0.06%	0.81%	15.00%	15.87%	0.0093%
Loews Corp	L	12,767.50	N/A	0.00%	N/A	N/A	N/A
L Brands Inc	LB	15,201.41	0.05%	1.25%	14.50%	15.84%	0.0073%
Leidos Holdings Inc	LDOS	12,550.59	0.04%	1.63%	10.42%	12.14%	0.0046%
Leggett & Platt Inc	LEG	5,754.37	0.02%	3.78%	1.00%	4.80%	0.0008%
Lennar Corp	LEN	25,263.91	0.08%	1.00%	10.59%	11.64%	0.0089%
Laboratory Corp of America Holdings	LH	23,415.22	0.07%	0.00%	6.72%	6.72%	0.0048%
L3Harris Technologies Inc	LHX	38,221.48	0.12%	2.20%	8.70%	11.00%	0.0128%
Linde PLC	LIN	127,734.36	0.39%	1.75%	11.08%	12.92%	0.0502%
LKQ Corp	LKQ	11,947.48	0.04%	0.00%	9.40%	9.40%	0.0034%
Eli Lilly and Co	LLY	196,371.84	N/A	1.65%	N/A	N/A	N/A

Company	Ticker	[2] Market Capitalization	[3] Weight in Index	[4] Estimated Dividend Yield	[5] Long-Term Growth Est.	[6] DCF Result	[7] Weighted DCF Result
Lockheed Martin Corp	LMT	92,504.16	0.28%	3.24%	5.20%	8.52%	0.0240%
Lincoln National Corp	LNC	10,916.67	0.03%	2.98%	28.56%	31.97%	0.0106%
Alliant Energy Corp	LNT	11,534.51	0.04%	3.50%	6.12%	9.72%	0.0034%
Lowe's Cos Inc	LOW	116,777.25	0.36%	1.64%	19.01%	20.80%	0.0739%
Lam Research Corp	LRCX	81,056.17	0.25%	0.90%	17.18%	18.16%	0.0448%
Lumen Technologies Inc	LUMN	13,480.27	0.04%	8.14%	-4.52%	3.44%	0.0014%
Southwest Airlines Co	LUV	34,336.08	0.10%	0.31%	4.40%	4.72%	0.0049%
Las Vegas Sands Corp	LVS	47,816.57	0.15%	3.38%	9.35%	12.89%	0.0187%
Lamb Weston Holdings Inc	LW	11,674.74	0.04%	1.17%	12.87%	14.12%	0.0050%
LyondellBasell Industries NV	LYB	34,445.73	0.10%	4.14%	5.50%	9.75%	0.0102%
Live Nation Entertainment Inc	LYV	19,372.82	N/A	0.00%	N/A	N/A	N/A
Mastercard Inc	MA	351,501.26	1.07%	0.45%	22.32%	22.83%	0.2439%
Mid-America Apartment Communities Inc	MAA	15,411.68	N/A	3.06%	N/A	N/A	N/A
Marriott International Inc/MD	MAR	48,036.00	0.15%	0.12%	4.91%	5.03%	0.0073%
Masco Corp	MAS	13,685.12	0.04%	1.47%	9.73%	11.28%	0.0047%
McDonald's Corp	MCD	153,692.24	N/A	2.54%	N/A	N/A	N/A
Microchip Technology Inc	MCHP	41,097.46	0.12%	0.90%	12.80%	13.76%	0.0172%
McKesson Corp	MCK	26,982.06	0.08%	1.00%	4.88%	5.91%	0.0048%
Moody's Corp	MCO	51,431.92	0.16%	0.91%	11.30%	12.26%	0.0192%
Mondelez International Inc	MDLZ	75,068.01	0.23%	2.43%	8.62%	11.15%	0.0254%
Medtronic PLC	MDT	157,613.67	0.48%	1.93%	9.02%	11.04%	0.0529%
MetLife Inc	MET	50,941.40	0.15%	3.32%	4.75%	8.15%	0.0126%
MGM Resorts International	MGM	18,694.62	0.06%	0.33%	0.55%	0.88%	0.0005%
Mohawk Industries Inc	MHK	12,288.91	0.04%	0.00%	13.36%	13.36%	0.0050%
McCormick & Co Inc/MD	MKC	22,500.47	0.07%	1.78%	5.72%	7.55%	0.0052%
MarketAxess Holdings Inc	MKTX	21,123.43	N/A	0.47%	N/A	N/A	N/A
Martin Marietta Materials Inc	MLM	20,982.55	0.06%	0.69%	11.39%	12.12%	0.0077%
Marsh & McLennan Cos Inc	MMC	58,553.26	0.18%	1.70%	8.16%	9.93%	0.0177%
3M Co	MMM	101,377.25	0.31%	3.44%	8.05%	11.63%	0.0358%
Monster Beverage Corp	MNST	46,335.23	0.14%	0.00%	13.07%	13.07%	0.0184%
Altria Group Inc	MO	81,038.87	0.25%	8.12%	3.70%	11.97%	0.0295%
Mosaic Co/The	MOS	11,145.34	0.03%	0.67%	18.05%	18.78%	0.0064%
Marathon Petroleum Corp	MPC	35,538.54	0.11%	4.21%	25.82%	30.57%	0.0330%
Monolithic Power Systems Inc	MPWR	16,953.40	0.05%	0.62%	18.55%	19.23%	0.0099%
Merck & Co Inc	MRK	183,751.52	0.56%	3.60%	10.84%	14.63%	0.0817%
Marathon Oil Corp	MRO	8,758.74	0.03%	1.15%	0.90%	2.06%	0.0005%
Morgan Stanley	MS	139,073.07	0.42%	1.94%	12.06%	14.12%	0.0597%
MSCI Inc	MSCI	34,228.84	0.10%	0.77%	12.70%	13.52%	0.0141%
Microsoft Corp	MSFT	1,752,660.10	5.33%	0.96%	16.60%	17.64%	0.9402%
Motorola Solutions Inc	MSI	29,661.09	0.09%	1.63%	11.30%	13.03%	0.0117%
M&T Bank Corp	MTB	19,416.41	0.06%	2.93%	9.57%	12.64%	0.0075%
Mettler-Toledo International Inc	MTD	26,124.55	0.08%	0.00%	13.45%	13.45%	0.0107%
Micron Technology Inc	MU	102,392.00	0.31%	0.00%	15.72%	15.72%	0.0489%
Maxim Integrated Products Inc	MXIM	24,973.39	0.08%	0.71%	11.30%	12.05%	0.0091%
Norwegian Cruise Line Holdings Ltd	NCLH	9,330.20	0.03%	0.00%	-22.09%	-22.09%	-0.0063%
Nasdaq Inc	NDAQ	22,789.59	0.07%	1.46%	6.85%	8.36%	0.0058%
NextEra Energy Inc	NEE	144,011.59	0.44%	2.09%	8.30%	10.48%	0.0459%
Newmont Corp	NEM	43,521.09	0.13%	3.69%	-6.75%	-3.18%	-0.0042%
Netflix Inc	NFLX	238,654.11	0.73%	0.00%	26.20%	26.20%	0.1901%
NiSource Inc	NI	8,464.17	0.03%	4.09%	5.35%	9.55%	0.0025%
NIKE Inc	NKE	212,479.32	0.65%	0.77%	26.79%	27.66%	0.1787%
NortonLifeLock Inc	NLOK	11,352.88	0.03%	2.81%	13.43%	16.43%	0.0057%
Nielsen Holdings PLC	NLSN	8,018.11	N/A	1.07%	N/A	N/A	N/A
Northrop Grumman Corp	NOC	48,625.08	0.15%	2.13%	4.61%	6.79%	0.0100%
NOV Inc	NOV	5,861.99	0.02%	0.22%	2.80%	3.02%	0.0005%
ServiceNow Inc	NOW	104,611.51	0.32%	0.00%	29.37%	29.37%	0.0934%
NRG Energy Inc	NRG	8,916.50	0.03%	3.29%	-8.76%	-5.62%	-0.0015%
Norfolk Southern Corp	NSC	63,496.85	0.19%	1.63%	10.91%	12.63%	0.0244%
NetApp Inc	NTAP	13,983.89	0.04%	3.07%	9.10%	12.31%	0.0052%
Northern Trust Corp	NTRS	19,816.95	0.06%	2.99%	6.42%	9.51%	0.0057%
Nucor Corp	NUE	18,061.39	0.05%	2.71%	4.95%	7.73%	0.0042%
NVIDIA Corp	NVDA	339,571.02	1.03%	0.12%	17.90%	18.04%	0.1862%
NVR Inc	NVR	16,568.41	0.05%	0.00%	13.96%	13.96%	0.0070%
Newell Brands Inc	NWL	9,837.98	0.03%	3.97%	2.00%	6.01%	0.0018%
News Corp	NWS	13,746.65	0.04%	0.87%	30.80%	31.81%	0.0133%
Realty Income Corp	O	22,500.52	0.07%	4.73%	3.98%	8.80%	0.0060%
Old Dominion Freight Line Inc	ODFL	25,114.58	0.08%	0.38%	15.86%	16.27%	0.0124%
ONEOK Inc	OKE	19,708.32	0.06%	8.45%	13.10%	22.10%	0.0132%
Omnicom Group Inc	OMC	14,777.94	0.04%	3.02%	9.02%	12.18%	0.0055%
Oracle Corp	ORCL	189,919.63	0.58%	1.50%	7.74%	9.30%	0.0537%
O'Reilly Automotive Inc	ORLY	31,405.55	0.10%	0.00%	11.77%	11.77%	0.0112%
Otis Worldwide Corp	OTIS	27,629.18	0.08%	1.41%	2.20%	3.63%	0.0030%
Occidental Petroleum Corp	OXY	24,779.48	0.08%	0.53%	13.95%	14.52%	0.0109%
Paycom Software Inc	PAYC	22,524.96	0.07%	0.00%	26.25%	26.25%	0.0180%
Paychex Inc	PAYX	32,842.68	0.10%	2.73%	8.50%	11.34%	0.0113%
People's United Financial Inc	PBCT	7,618.76	N/A	4.06%	N/A	N/A	N/A
PACCAR Inc	PCAR	31,567.78	0.10%	2.23%	11.65%	14.01%	0.0134%
Healthpeak Properties Inc	PEAK	15,670.38	0.05%	4.65%	2.32%	7.02%	0.0033%
Public Service Enterprise Group Inc	PEG	27,229.80	0.08%	3.80%	3.30%	7.16%	0.0059%
PepsiCo Inc	PEP	178,231.64	0.54%	3.30%	7.39%	10.81%	0.0586%
Pfizer Inc	PFE	186,794.81	0.57%	4.66%	2.35%	7.06%	0.0401%
Principal Financial Group Inc	PFG	15,424.48	0.05%	4.03%	15.69%	20.03%	0.0094%
Procter & Gamble Co/The	PG	304,189.67	0.92%	2.62%	7.25%	9.97%	0.0922%
Progressive Corp/The	PGR	50,340.92	0.15%	2.55%	-1.64%	0.89%	0.0014%
Parker-Hannifin Corp	PH	37,041.13	0.11%	1.26%	12.83%	14.17%	0.0160%
PulteGroup Inc	PHM	11,994.49	0.04%	1.22%	10.25%	11.54%	0.0042%
Packaging Corp of America	PKG	12,519.22	0.04%	3.04%	1.63%	4.70%	0.0018%
PerkinElmer Inc	PKI	14,118.86	0.04%	0.22%	-3.97%	-3.75%	-0.0016%
Prologis Inc	PLD	73,171.32	0.22%	2.49%	6.55%	9.12%	0.0203%
Philip Morris International Inc	PM	130,857.10	0.40%	5.78%	9.14%	15.18%	0.0604%
PNC Financial Services Group Inc/The	PNC	71,334.31	0.22%	2.78%	17.33%	20.35%	0.0441%
Pentair PLC	PNR	9,287.93	0.03%	1.43%	9.07%	10.57%	0.0030%
Pinnacle West Capital Corp	PNW	7,880.52	0.02%	4.79%	2.66%	7.51%	0.0018%
Pool Corp	POOL	13,467.59	0.04%	0.76%	17.00%	17.82%	0.0073%
PPG Industries Inc	PPG	31,923.87	0.10%	1.66%	6.93%	8.65%	0.0084%
PPL Corp	PPL	20,139.71	0.06%	5.93%	-0.10%	5.82%	0.0036%

Company	Ticker	[2] Market Capitalization	[3] Weight in Index	[4] Estimated Dividend Yield	[5] Long-Term Growth Est.	[6] DCF Result	[7] Weighted DCF Result
Perrigo Co PLC	PRGO	5,508.79	0.02%	2.25%	-2.80%	-0.58%	-0.0001%
Prudential Financial Inc	PRU	34,427.84	0.10%	5.35%	5.73%	11.24%	0.0118%
Public Storage	PSA	40,918.95	0.12%	3.49%	3.21%	6.75%	0.0084%
Phillips 66	PSX	36,286.71	0.11%	4.38%	7.63%	12.18%	0.0134%
PVH Corp	PVH	7,107.18	0.02%	0.04%	1.68%	1.72%	0.0004%
Quanta Services Inc	PWR	11,643.49	N/A	0.27%	N/A	N/A	N/A
Pioneer Natural Resources Co	PXD	32,107.31	0.10%	1.49%	15.13%	16.74%	0.0163%
PayPal Holdings Inc	PYPL	304,330.02	0.93%	0.00%	22.07%	22.07%	0.2042%
QUALCOMM Inc	QCOM	154,711.84	0.47%	1.97%	19.80%	21.96%	0.1033%
Qorvo Inc	QRVO	19,790.39	0.06%	0.00%	18.00%	18.00%	0.0108%
Royal Caribbean Cruises Ltd	RCL	22,142.17	0.07%	3.10%	-36.25%	-33.72%	-0.0227%
Everest Re Group Ltd	RE	9,668.53	N/A	2.67%	N/A	N/A	N/A
Regency Centers Corp	REG	9,312.31	0.03%	4.37%	2.71%	7.13%	0.0020%
Regeneron Pharmaceuticals Inc	REGN	48,270.42	0.15%	0.00%	8.43%	8.43%	0.0124%
Regions Financial Corp	RF	19,818.71	0.06%	3.09%	26.00%	29.49%	0.0178%
Robert Half International Inc	RHI	8,799.98	0.03%	1.86%	10.13%	12.08%	0.0032%
Raymond James Financial Inc	RJF	16,076.40	0.05%	1.35%	13.50%	14.94%	0.0073%
Ralph Lauren Corp	RL	8,560.70	0.03%	0.45%	0.66%	1.11%	0.0003%
ResMed Inc	RMD	28,051.24	0.09%	0.83%	12.73%	13.61%	0.0116%
Rockwell Automation Inc	ROK	28,258.21	0.09%	1.76%	11.04%	12.90%	0.0111%
Rollins Inc	ROL	16,324.35	N/A	1.24%	N/A	N/A	N/A
Roper Technologies Inc	ROP	39,627.29	0.12%	0.59%	13.70%	14.33%	0.0173%
Ross Stores Inc	ROST	41,577.86	0.13%	0.29%	8.85%	9.16%	0.0116%
Republic Services Inc	RSG	28,410.65	0.09%	1.96%	7.94%	9.98%	0.0086%
Raytheon Technologies Corp	RTX	109,387.23	0.33%	2.76%	13.86%	16.81%	0.0559%
SBA Communications Corp	SBAC	27,891.93	0.08%	0.90%	28.70%	29.73%	0.0252%
Starbucks Corp	SBUX	127,183.72	0.39%	1.85%	22.60%	24.65%	0.0953%
Charles Schwab Corp/The	SCHW	116,178.25	0.35%	1.21%	7.68%	8.93%	0.0316%
Sealed Air Corp	SEE	6,491.12	0.02%	1.56%	7.19%	8.81%	0.0017%
Sherwin-Williams Co/The	SHW	60,959.74	0.19%	0.91%	9.07%	10.02%	0.0186%
SVB Financial Group	SIVB	26,222.35	0.08%	0.00%	8.00%	8.00%	0.0064%
J M Smucker Co/The	SJM	12,273.59	0.04%	3.22%	1.28%	4.51%	0.0017%
Schlumberger NV	SLB	39,025.69	0.12%	1.85%	20.96%	23.00%	0.0273%
SL Green Realty Corp	SLG	4,941.09	0.02%	5.40%	3.95%	9.46%	0.0014%
Snap-on Inc	SNA	11,009.19	0.03%	2.35%	6.83%	9.26%	0.0031%
Synopsys Inc	SNPS	37,363.42	0.11%	0.00%	14.72%	14.72%	0.0167%
Southern Co/The	SO	59,922.68	0.18%	4.62%	5.20%	9.94%	0.0181%
Simon Property Group Inc	SPG	37,094.38	0.11%	4.85%	-0.07%	4.78%	0.0054%
S&P Global Inc	SPGI	79,276.95	0.24%	0.92%	8.30%	9.25%	0.0223%
Sempra Energy	SRE	33,456.78	0.10%	3.87%	4.29%	8.24%	0.0084%
STERIS PLC	STE	14,919.65	0.05%	0.90%	11.80%	12.75%	0.0058%
State Street Corp	STT	25,599.49	0.08%	2.95%	7.80%	10.86%	0.0084%
Seagate Technology PLC	STX	17,332.23	0.05%	3.62%	4.50%	8.21%	0.0043%
Constellation Brands Inc	STZ	41,714.87	0.13%	1.41%	7.91%	9.37%	0.0119%
Stanley Black & Decker Inc	SWK	28,130.53	0.09%	1.65%	9.82%	11.55%	0.0099%
Skyworks Solutions Inc	SWKS	29,322.52	0.09%	0.90%	17.55%	18.52%	0.0165%
Synchrony Financial	SYF	22,584.55	0.07%	2.38%	94.02%	97.51%	0.0670%
Stryker Corp	SYK	91,300.21	0.28%	1.06%	8.38%	9.48%	0.0263%
Sysco Corp	SYY	40,644.10	0.12%	2.29%	6.50%	8.87%	0.0110%
AT&T Inc	T	198,904.88	0.60%	7.50%	0.73%	8.26%	0.0499%
Molson Coors Beverage Co	TAP	9,693.21	0.03%	2.54%	7.38%	10.02%	0.0030%

Company	Ticker	[2] Market Capitalization	[3] Weight in Index	[4] Estimated Dividend Yield	[5] Long-Term Growth Est.	[6] DCF Result	[7] Weighted DCF Result
TransDigm Group Inc	TDG	31,537.46	0.10%	6.44%	18.39%	25.41%	0.0244%
Teledyne Technologies Inc	TDY	13,709.73	0.04%	0.00%	11.60%	11.60%	0.0048%
TE Connectivity Ltd	TEL	43,025.47	0.13%	1.49%	12.28%	13.86%	0.0181%
Teradyne Inc	TER	21,438.61	0.07%	0.32%	15.00%	15.34%	0.0100%
Truist Financial Corp	TFC	76,736.43	0.23%	3.20%	11.32%	14.71%	0.0343%
Teleflex Inc	TFX	18,588.15	0.06%	0.35%	12.03%	12.41%	0.0070%
Target Corp	TGT	91,861.82	0.28%	1.47%	11.57%	13.13%	0.0367%
TJX Cos Inc/The	TJX	79,229.65	0.24%	1.58%	9.13%	10.78%	0.0260%
Thermo Fisher Scientific Inc	TMO	177,238.52	0.54%	0.23%	9.90%	10.14%	0.0547%
T-Mobile US Inc	TMUS	149,099.21	0.45%	0.00%	14.95%	14.95%	0.0678%
Tapestry Inc	TPR	11,708.10	0.04%	0.80%	13.18%	14.03%	0.0050%
Trimble Inc	TRMB	18,548.02	0.06%	0.00%	8.25%	8.25%	0.0047%
T Rowe Price Group Inc	TROW	36,959.18	0.11%	2.41%	13.15%	15.72%	0.0177%
Travelers Cos Inc/The	TRV	36,697.19	0.11%	2.45%	7.36%	9.90%	0.0110%
Tractor Supply Co	TSCO	18,487.34	0.06%	1.25%	7.37%	8.66%	0.0049%
Tesla Inc	TSLA	648,381.04	1.97%	0.00%	37.85%	37.85%	0.7461%
Tyson Foods Inc	TSN	24,681.46	0.08%	2.66%	5.66%	8.39%	0.0063%
Trane Technologies PLC	TT	36,536.81	0.11%	1.52%	11.58%	13.19%	0.0146%
Take-Two Interactive Software Inc	TTWO	21,245.67	0.06%	0.00%	6.38%	6.38%	0.0041%
Twitter Inc	TWTR	61,505.63	0.19%	0.00%	80.00%	80.00%	0.1496%
Texas Instruments Inc	TXN	158,529.61	0.48%	2.42%	10.03%	12.58%	0.0606%
Textron Inc	TXT	11,391.16	0.03%	0.16%	26.22%	26.39%	0.0091%
Tyler Technologies Inc	TYL	18,804.07	0.06%	0.00%	18.43%	18.43%	0.0105%
Under Armour Inc	UA	9,041.54	0.03%	0.00%	40.90%	40.90%	0.0112%
United Airlines Holdings Inc	UAL	16,428.01	0.05%	0.00%	124.80%	124.80%	0.0623%
UDR Inc	UDR	12,220.12	0.04%	3.54%	1.69%	5.26%	0.0020%
Universal Health Services Inc	UHS	10,664.79	0.03%	0.53%	7.58%	8.13%	0.0026%
Ulta Beauty Inc	ULTA	18,159.63	0.06%	0.00%	1.70%	1.70%	0.0009%
UnitedHealth Group Inc	UNH	315,217.22	0.96%	1.56%	12.14%	13.79%	0.1322%
Unum Group	UNM	5,394.80	0.02%	4.43%	3.33%	7.83%	0.0013%
Union Pacific Corp	UNP	137,958.06	0.42%	1.99%	10.60%	12.70%	0.0533%
United Parcel Service Inc	UPS	136,844.69	0.42%	2.67%	8.04%	10.82%	0.0450%
United Rentals Inc	URI	21,470.62	0.07%	0.00%	0.37%	0.37%	0.0002%
US Bancorp	USB	75,106.81	0.23%	3.40%	4.40%	7.88%	0.0180%
Visa Inc	V	469,271.00	1.43%	0.60%	18.34%	18.99%	0.2710%
Varian Medical Systems Inc	VAR	16,096.59	N/A	0.00%	N/A	N/A	N/A
VF Corp	VFC	30,996.31	0.09%	2.41%	7.83%	10.33%	0.0097%
ViacomCBS Inc	VIAC	39,946.42	0.12%	1.53%	-0.17%	1.35%	0.0016%
Valero Energy Corp	VLO	31,451.17	0.10%	5.10%	-3.95%	1.05%	0.0010%
Vulcan Materials Co	VMC	22,134.04	0.07%	0.85%	13.82%	14.74%	0.0099%
Vornado Realty Trust	VNO	8,216.77	0.02%	5.14%	-1.41%	3.70%	0.0009%
Vontier Corp	VNT	5,292.36	0.02%	0.00%	7.15%	7.15%	0.0012%
Verisk Analytics Inc	VRSK	26,673.40	0.08%	0.71%	9.53%	10.28%	0.0083%
VeriSign Inc	VRSN	21,943.74	0.07%	0.00%	4.30%	4.30%	0.0029%
Vertex Pharmaceuticals Inc	VRTX	55,254.51	0.17%	0.00%	35.02%	35.02%	0.0588%
Ventas Inc	VTR	19,819.46	0.06%	3.39%	2.02%	5.44%	0.0033%
Viatris Inc	VTRS	18,051.20	0.05%	0.00%	-6.27%	-6.27%	-0.0034%
Verizon Communications Inc	VZ	228,839.62	0.70%	4.58%	2.35%	6.98%	0.0486%
Westinghouse Air Brake Technologies Corp	WAB	13,681.74	0.04%	0.71%	5.39%	6.12%	0.0025%
Waters Corp	WAT	17,031.42	0.05%	0.00%	8.27%	8.27%	0.0043%
Walgreens Boots Alliance Inc	WBA	41,413.52	0.13%	3.96%	3.64%	7.66%	0.0096%
Western Digital Corp	WDC	20,976.84	0.06%	0.21%	5.35%	5.56%	0.0035%
WEC Energy Group Inc	WEC	25,436.64	0.08%	3.35%	6.58%	10.04%	0.0078%
Welltower Inc	WELL	28,340.31	0.09%	3.65%	3.45%	7.16%	0.0062%
Wells Fargo & Co	WFC	149,530.64	0.45%	1.38%	6.01%	7.42%	0.0337%
Whirlpool Corp	WHR	11,971.15	0.04%	2.65%	2.98%	5.67%	0.0021%
Willis Towers Watson PLC	WLTW	28,456.06	0.09%	1.33%	10.00%	11.40%	0.0099%
Waste Management Inc	WM	46,923.43	0.14%	2.08%	9.07%	11.24%	0.0160%
Williams Cos Inc/The	WMB	27,722.97	0.08%	7.20%	9.50%	17.04%	0.0144%
Walmart Inc	WMT	367,580.83	1.12%	1.71%	6.27%	8.03%	0.0897%
W R Berkley Corp	WRB	12,296.50	0.04%	1.53%	14.65%	16.29%	0.0061%
Westrock Co	WRK	11,486.70	0.03%	2.08%	10.42%	12.61%	0.0044%
West Pharmaceutical Services Inc	WST	20,797.01	0.06%	0.25%	18.01%	18.28%	0.0116%
Western Union Co/The	WU	9,541.60	0.03%	4.05%	4.57%	8.71%	0.0025%
Weyerhaeuser Co	WY	25,326.90	0.08%	2.35%	3.80%	6.19%	0.0048%
Wynn Resorts Ltd	WYNN	15,230.14	0.05%	1.65%	-1.60%	0.03%	0.0000%
Xcel Energy Inc	XEL	31,500.85	0.10%	3.11%	6.51%	9.73%	0.0093%
Xilinx Inc	XLNX	31,959.59	0.10%	1.17%	6.95%	8.16%	0.0079%
Exxon Mobil Corp	XOM	229,889.09	0.70%	6.41%	8.53%	15.21%	0.1063%
DENTSPLY SIRONA Inc	XRAY	11,598.73	0.04%	0.73%	0.51%	1.24%	0.0004%
Xerox Holdings Corp	XRX	5,054.85	0.02%	3.92%	24.40%	28.80%	0.0044%
Xylem Inc/NY	XYL	17,943.90	0.05%	1.12%	15.90%	17.11%	0.0093%
Yum! Brands Inc	YUM	31,064.73	0.09%	1.95%	12.06%	14.13%	0.0133%
Zimmer Biomet Holdings Inc	ZBH	33,892.92	0.10%	0.61%	9.67%	10.31%	0.0106%
Zebra Technologies Corp	ZBRA	26,703.23	0.08%	0.00%	13.10%	13.10%	0.0106%
Zions Bancorp NA	ZION	8,731.26	0.03%	2.61%	8.93%	11.65%	0.0031%
Zoetis Inc	ZTS	73,764.83	0.22%	0.60%	11.91%	12.54%	0.0281%
	Total Market Capitalization:	32,891,765.32					16.35%

Notes:
[1] Equals sum of Col. [7]
[2] Source: Bloomberg Professional Service
[3] Equals weight in S&P 500 based on market capitalization
[4] Source: Bloomberg Professional Service
[5] Source: Bloomberg Professional Service
[6] Equals ([4] x (1 + (0.5 x [5]))) + [5]
[7] Equals Col. [3] x Col. [6]

Expected Market Return
Market DCF Method Based - Value Line

[1]
S&P 500 Est. Required Market Return
14.34%

Company	Ticker	[2] Market Capitalization	[3] Weight in Index	[4] Estimated Dividend Yield	[5] Long-Term Growth Est.	[6] DCF Result	[7] Weighted DCF Result
Agilent Technologies Inc	A	39,816.72	0.12%	0.60%	10.50%	11.13%	0.0134%
American Airlines Group Inc	AAL	9,149.79	0.03%	0.00%	-3.50%	-3.50%	-0.0010%
Advance Auto Parts Inc	AAP	11,075.77	0.03%	0.62%	11.00%	11.65%	0.0039%
Apple Inc	AAPL	2,201,156.00	6.65%	0.67%	16.00%	16.72%	1.1123%
AbbVie Inc	ABBV	187,633.20	0.57%	4.89%	10.50%	15.65%	0.0887%
AmerisourceBergen Corp	ABC	21,507.04	0.06%	1.67%	7.00%	8.73%	0.0057%
ABIOMED Inc	ABMD	14,304.67	0.04%	0.00%	10.00%	10.00%	0.0043%
Abbott Laboratories	ABT	225,515.30	0.68%	1.42%	12.00%	13.51%	0.0920%
Accenture PLC	ACN	164,104.60	0.50%	1.42%	8.00%	9.48%	0.0470%
Adobe Inc	ADBE	235,299.20	0.71%	0.00%	14.00%	14.00%	0.0995%
Analog Devices Inc	ADI	58,930.82	0.18%	1.73%	8.50%	10.30%	0.0183%
Archer-Daniels-Midland Co	ADM	31,091.52	0.09%	2.72%	9.00%	11.84%	0.0111%
Automatic Data Processing Inc	ADP	71,548.35	0.22%	2.31%	9.00%	11.41%	0.0247%
Autodesk Inc	ADSK	66,463.65	N/A	0.00%	N/A	N/A	N/A
Ameren Corp	AEE	18,119.76	0.05%	3.00%	6.00%	9.09%	0.0050%
American Electric Power Co Inc	AEP	40,386.80	0.12%	3.82%	6.00%	9.93%	0.0121%
AES Corp/The	AES	19,129.17	0.06%	2.09%	28.00%	30.38%	0.0176%
Aflac Inc	AFL	33,096.12	0.10%	2.87%	8.50%	11.49%	0.0115%
American International Group Inc	AIG	37,274.89	0.11%	2.96%	28.50%	31.88%	0.0359%
Assurant Inc	AIZ	7,427.16	0.02%	2.10%	11.50%	13.72%	0.0031%
Arthur J Gallagher & Co	AJG	22,628.61	0.07%	1.63%	13.00%	14.74%	0.0101%
Akamai Technologies Inc	AKAM	16,597.46	0.05%	0.00%	15.00%	15.00%	0.0075%
Albemarle Corp	ALB	16,763.78	0.05%	0.98%	6.50%	7.51%	0.0038%
Align Technology Inc	ALGN	47,272.34	0.14%	0.00%	19.00%	19.00%	0.0271%
Alaska Air Group Inc	ALK	7,418.42	0.02%	0.00%	1.50%	1.50%	0.0003%
Allstate Corp/The	ALL	31,877.44	0.10%	2.06%	9.00%	11.15%	0.0107%
Allegion plc	ALLE	10,082.92	0.03%	1.32%	9.00%	10.38%	0.0032%
Alexion Pharmaceuticals Inc	ALXN	34,387.38	0.10%	0.00%	20.50%	20.50%	0.0213%
Applied Materials Inc	AMAT	105,758.90	0.32%	0.78%	8.50%	9.31%	0.0298%
Amcor PLC	AMCR	18,294.70	N/A	4.16%	N/A	N/A	N/A
Advanced Micro Devices Inc	AMD	108,107.90	0.33%	0.00%	27.50%	27.50%	0.0898%
AMETEK Inc	AME	27,656.12	0.08%	0.67%	12.50%	13.21%	0.0110%
Amgen Inc	AMGN	136,253.30	0.41%	2.99%	7.00%	10.09%	0.0416%
Ameriprise Financial Inc	AMP	25,908.04	0.08%	1.91%	12.00%	14.02%	0.0110%
American Tower Corp	AMT	100,524.60	0.30%	2.39%	10.00%	12.51%	0.0380%
Amazon.com Inc	AMZN	1,660,937.00	5.02%	0.00%	35.50%	35.50%	1.7816%
Arista Networks Inc	ANET	23,613.07	0.07%	0.00%	5.50%	5.50%	0.0039%
ANSYS Inc	ANSS	33,817.89	0.10%	0.00%	10.00%	10.00%	0.0102%
Anthem Inc	ANTM	72,401.12	0.22%	1.46%	14.00%	15.56%	0.0340%
Aon PLC	AON	52,532.64	0.16%	0.81%	7.50%	8.34%	0.0132%
A O Smith Corp	AOS	9,568.54	0.03%	1.76%	5.00%	6.80%	0.0020%
Apache Corp	APA	7,054.73	0.02%	0.54%	8.50%	9.06%	0.0019%
Air Products and Chemicals Inc	APD	57,534.23	0.17%	2.31%	12.50%	14.95%	0.0260%
Amphenol Corp	APH	40,097.22	0.12%	0.87%	11.00%	11.92%	0.0144%
Aptiv PLC	APTV	42,277.82	0.13%	0.00%	9.50%	9.50%	0.0121%
Alexandria Real Estate Equities Inc	ARE	18,816.53	0.06%	2.57%	14.50%	17.26%	0.0098%
Atmos Energy Corp	ATO	11,845.18	0.04%	2.81%	7.00%	9.91%	0.0035%
Activision Blizzard Inc	ATVI	79,096.70	0.24%	0.46%	14.50%	14.99%	0.0358%
AvalonBay Communities Inc	AVB	25,175.28	0.08%	3.67%	1.00%	4.69%	0.0036%
Broadcom Inc	AVGO	194,921.90	0.59%	2.99%	18.50%	21.77%	0.1282%
Avery Dennison Corp	AVY	14,643.98	0.04%	1.41%	9.50%	10.98%	0.0049%
American Water Works Co Inc	AWK	29,144.59	0.09%	1.46%	8.50%	10.02%	0.0088%
American Express Co	AXP	103,490.80	0.31%	1.40%	6.00%	7.44%	0.0233%
AutoZone Inc	AZO	27,265.33	0.08%	0.00%	12.00%	12.00%	0.0099%
Boeing Co/The	BA	121,664.50	0.37%	0.00%	-1.50%	-1.50%	-0.0055%
Bank of America Corp	BAC	298,043.00	0.90%	2.09%	4.00%	6.13%	0.0552%
Baxter International Inc	BAX	39,678.09	0.12%	1.26%	8.50%	9.81%	0.0118%
Best Buy Co Inc	BBY	30,531.72	0.09%	2.03%	9.00%	11.12%	0.0103%
Becton Dickinson and Co	BDX	74,482.17	0.23%	1.31%	9.00%	10.37%	0.0233%
Franklin Resources Inc	BEN	13,991.49	0.04%	4.05%	18.00%	22.41%	0.0095%
Brown-Forman Corp	BF/B	36,361.82	0.11%	0.95%	12.00%	13.01%	0.0143%
Biogen Inc	BIIB	42,579.51	0.13%	0.00%	1.00%	1.00%	0.0013%
Bio-Rad Laboratories Inc	BIO	19,560.78	0.06%	0.00%	14.50%	14.50%	0.0086%
Bank of New York Mellon Corp/The	BK	38,015.23	0.11%	2.89%	3.00%	5.93%	0.0068%
Booking Holdings Inc	BKNG	91,481.82	0.28%	0.00%	7.00%	7.00%	0.0193%
Baker Hughes Co	BKR	16,131.75	0.05%	3.06%	34.50%	38.09%	0.0186%
BlackRock Inc	BLK	110,009.10	0.33%	2.29%	9.50%	11.90%	0.0396%
Ball Corp	BLL	29,382.33	0.09%	0.67%	18.00%	18.73%	0.0166%
Bristol-Myers Squibb Co	BMY	136,918.40	0.41%	3.24%	12.50%	15.94%	0.0660%
Broadridge Financial Solutions Inc	BR	17,072.39	0.05%	1.56%	8.50%	10.13%	0.0052%
Berkshire Hathaway Inc	BRK/B	-	N/A	0.00%	N/A	N/A	N/A
Boston Scientific Corp	BSX	53,694.82	0.16%	0.00%	12.00%	12.00%	0.0195%
BorgWarner Inc	BWA	10,898.21	0.03%	1.53%	4.00%	5.56%	0.0018%
Boston Properties Inc	BXP	14,356.77	0.04%	4.23%	4.00%	8.31%	0.0036%
Citigroup Inc	C	134,827.70	0.41%	3.15%	3.50%	6.71%	0.0273%
Conagra Brands Inc	CAG	16,597.03	0.05%	3.33%	5.50%	8.92%	0.0045%
Cardinal Health Inc	CAH	15,205.68	0.05%	3.79%	11.50%	15.51%	0.0071%
Carrier Global Corp	CARR	32,275.42	N/A	1.29%	N/A	N/A	N/A
Caterpillar Inc	CAT	109,901.10	0.33%	2.04%	7.00%	9.11%	0.0303%
Chubb Ltd	CB	75,099.94	0.23%	1.88%	9.50%	11.47%	0.0260%
Cboe Global Markets Inc	CBOE	10,400.12	0.03%	1.75%	12.50%	14.36%	0.0045%

Company	Ticker	[2] Market Capitalization	[3] Weight in Index	[4] Estimated Dividend Yield	[5] Long-Term Growth Est.	[6] DCF Result	[7] Weighted DCF Result
CBRE Group Inc	CBRE	23,386.81	0.07%	0.00%	6.50%	6.50%	0.0046%
Crown Castle International Corp	CCI	70,309.03	0.21%	3.42%	11.50%	15.12%	0.0321%
Carnival Corp	CCL	19,256.00	0.06%	0.00%	-10.00%	-10.00%	-0.0058%
Cadence Design Systems Inc	CDNS	39,546.84	0.12%	0.00%	13.00%	13.00%	0.0155%
CDW Corp/DE	CDW	22,542.41	0.07%	1.01%	11.00%	12.07%	0.0082%
Celanese Corp	CE	15,523.60	0.05%	2.05%	5.50%	7.61%	0.0036%
Cerner Corp	CERN	22,207.60	0.07%	1.21%	9.00%	10.26%	0.0069%
CF Industries Holdings Inc	CF	9,638.78	0.03%	2.89%	24.00%	27.24%	0.0079%
Citizens Financial Group Inc	CFG	17,864.46	0.05%	3.73%	1.50%	5.26%	0.0028%
Church & Dwight Co Inc	CHD	20,555.68	0.06%	1.22%	8.50%	9.77%	0.0061%
CH Robinson Worldwide Inc	CHRW	12,224.21	0.04%	2.31%	7.00%	9.39%	0.0035%
Charter Communications Inc	CHTR	120,910.80	0.37%	0.00%	36.50%	36.50%	0.1333%
Cigna Corp	CI	76,382.86	0.23%	1.92%	11.50%	13.53%	0.0312%
Cincinnati Financial Corp	CINF	15,083.04	0.05%	2.69%	10.50%	13.33%	0.0061%
Colgate-Palmolive Co	CL	67,236.34	0.20%	2.24%	5.00%	7.30%	0.0148%
Clorox Co/The	CLX	23,605.94	0.07%	2.37%	5.00%	7.43%	0.0053%
Comerica Inc	CMA	9,015.84	0.03%	4.20%	0.50%	4.71%	0.0013%
Comcast Corp	CMCSA	242,729.00	0.73%	1.89%	8.00%	9.97%	0.0731%
CME Group Inc	CME	68,434.43	0.21%	1.88%	2.50%	4.40%	0.0091%
Chipotle Mexican Grill Inc	CMG	40,835.35	0.12%	0.00%	18.00%	18.00%	0.0222%
Cummins Inc	CMI	35,812.06	0.11%	2.23%	5.50%	7.79%	0.0084%
CMS Energy Corp	CMS	16,131.52	0.05%	3.12%	7.50%	10.74%	0.0052%
Centene Corp	CNC	33,977.74	0.10%	0.00%	13.00%	13.00%	0.0133%
CenterPoint Energy Inc	CNP	11,729.95	0.04%	2.97%	5.00%	8.04%	0.0029%
Capital One Financial Corp	COF	54,389.08	0.16%	1.35%	2.00%	3.36%	0.0055%
Cabot Oil & Gas Corp	COG	7,405.62	0.02%	2.58%	13.50%	16.25%	0.0036%
Cooper Cos Inc/The	COO	18,886.32	0.06%	0.02%	13.50%	13.52%	0.0077%
ConocoPhillips	COP	52,950.55	0.16%	3.49%	3.50%	7.05%	0.0113%
Costco Wholesale Corp	COST	158,595.60	0.48%	0.82%	11.00%	11.87%	0.0569%
Campbell Soup Co	CPB	14,980.74	0.05%	3.19%	4.00%	7.25%	0.0033%
Copart Inc	CPRT	27,859.56	0.08%	0.00%	12.00%	12.00%	0.0101%
salesforce.com Inc	CRM	226,361.30	0.68%	0.00%	46.50%	46.50%	0.3180%
Cisco Systems Inc/Delaware	CSCO	195,221.30	0.59%	3.20%	7.00%	10.31%	0.0608%
CSX Corp	CSX	68,822.11	0.21%	1.25%	8.50%	9.80%	0.0204%
Cintas Corp	CTAS	35,601.80	0.11%	0.89%	13.00%	13.95%	0.0150%
Catalent Inc	CTLT	20,577.59	0.06%	0.00%	29.50%	29.50%	0.0183%
Cognizant Technology Solutions Corp	CTSH	41,195.77	0.12%	1.26%	5.00%	6.29%	0.0078%
Corteva Inc	CTVA	33,622.19	N/A	1.33%	N/A	N/A	N/A
Citrix Systems Inc	CTXS	16,490.36	0.05%	1.10%	9.00%	10.15%	0.0051%
CVS Health Corp	CVS	95,177.40	0.29%	2.75%	6.00%	8.83%	0.0254%
Chevron Corp	CVX	179,113.60	0.54%	5.38%	8.00%	13.60%	0.0736%
Dominion Energy Inc	D	59,070.24	0.18%	3.48%	7.00%	10.60%	0.0189%
Delta Air Lines Inc	DAL	28,309.01	0.09%	0.00%	4.50%	4.50%	0.0038%
DuPont de Nemours Inc	DD	51,361.82	N/A	1.83%	N/A	N/A	N/A
Deere & Co	DE	97,885.46	0.30%	0.97%	13.50%	14.54%	0.0430%
Discover Financial Services	DFS	28,105.68	0.08%	1.92%	5.50%	7.47%	0.0063%
Dollar General Corp	DG	49,367.50	0.15%	0.72%	13.00%	13.77%	0.0205%
Quest Diagnostics Inc	DGX	16,449.75	0.05%	2.04%	11.00%	13.15%	0.0065%
DR Horton Inc	DHI	28,506.37	0.09%	1.02%	12.00%	13.08%	0.0113%
Danaher Corp	DHR	170,408.10	0.51%	0.30%	16.50%	16.82%	0.0866%
Walt Disney Co/The	DIS	332,049.70	1.00%	0.00%	17.00%	17.00%	0.1706%
Discovery Inc	DISCA	24,482.56	0.07%	0.00%	15.50%	15.50%	0.0115%
DISH Network Corp	DISH	17,093.89	0.05%	0.00%	3.00%	3.00%	0.0015%
Digital Realty Trust Inc	DLR	28,886.83	0.09%	3.38%	7.00%	10.50%	0.0092%
Dollar Tree Inc	DLTR	25,476.87	0.08%	0.00%	8.50%	8.50%	0.0065%
Dover Corp	DOV	17,383.15	0.05%	1.64%	6.50%	8.19%	0.0043%
Dow Inc	DOW	43,422.16	N/A	5.13%	N/A	N/A	N/A
Domino's Pizza Inc	DPZ	14,830.69	0.04%	0.86%	15.00%	15.92%	0.0071%
Duke Realty Corp	DRE	15,166.90	0.05%	2.52%	-3.00%	-0.52%	-0.0002%
Darden Restaurants Inc	DRI	16,717.17	0.05%	1.15%	9.50%	10.70%	0.0054%
DTE Energy Co	DTE	23,256.23	0.07%	3.61%	6.00%	9.72%	0.0068%
Duke Energy Corp	DUK	65,651.20	0.20%	4.37%	5.00%	9.48%	0.0188%
DaVita Inc	DVA	11,335.19	0.03%	0.00%	13.00%	13.00%	0.0045%
Devon Energy Corp	DVN	8,322.59	0.03%	2.03%	4.50%	6.58%	0.0017%
DXC Technology Co	DXC	6,614.14	0.02%	0.00%	2.50%	2.50%	0.0005%
DexCom Inc	DXCM	39,755.52	0.12%	0.00%	52.50%	52.50%	0.0631%
Electronic Arts Inc	EA	42,063.64	0.13%	0.47%	9.50%	9.99%	0.0127%
eBay Inc	EBAY	43,441.45	0.13%	1.14%	18.50%	19.75%	0.0259%
Ecolab Inc	ECL	59,598.06	0.18%	0.92%	6.00%	6.95%	0.0125%
Consolidated Edison Inc	ED	23,433.44	0.07%	4.42%	2.50%	6.98%	0.0049%
Equifax Inc	EFX	21,473.34	0.06%	0.88%	5.50%	6.40%	0.0042%
Edison International	EIX	21,382.20	0.06%	4.74%	12.00%	17.02%	0.0110%
Estee Lauder Cos Inc/The	EL	105,014.90	0.32%	0.73%	11.50%	12.27%	0.0389%
Eastman Chemical Co	EMN	14,929.72	0.05%	2.50%	5.00%	7.56%	0.0034%
Emerson Electric Co	EMR	50,905.02	0.15%	2.38%	9.50%	11.99%	0.0184%
Enphase Energy Inc	ENPH	23,907.96	0.07%	0.00%	59.00%	59.00%	0.0426%
EOG Resources Inc	EOG	37,065.80	0.11%	2.52%	7.00%	9.61%	0.0108%
Equinix Inc	EQIX	61,875.11	0.19%	1.67%	14.50%	16.29%	0.0305%
Equity Residential	EQR	24,849.93	0.08%	3.61%	1.00%	4.63%	0.0035%
Eversource Energy	ES	28,225.90	0.09%	2.93%	6.50%	9.53%	0.0081%
Essex Property Trust Inc	ESS	17,631.36	0.05%	3.20%	1.00%	4.22%	0.0022%
Eaton Corp PLC	ETN	49,836.96	0.15%	2.34%	4.00%	6.39%	0.0096%
Entergy Corp	ETR	18,659.62	0.06%	4.14%	3.00%	7.20%	0.0041%
Etsy Inc	ETSY	27,948.04	0.08%	0.00%	32.00%	32.00%	0.0270%
Evergy Inc	EVRG	12,430.39	N/A	3.96%	N/A	N/A	N/A
Edwards Lifesciences Corp	EW	52,990.11	0.16%	0.00%	13.00%	13.00%	0.0208%
Exelon Corp	EXC	41,157.92	0.12%	3.82%	4.00%	7.90%	0.0098%
Expeditors International of Washington I	EXPD	15,978.79	0.05%	1.10%	5.50%	6.63%	0.0032%
Expedia Group Inc	EXPE	21,785.72	0.07%	0.00%	12.00%	12.00%	0.0079%
Extra Space Storage Inc	EXR	15,256.51	0.05%	3.06%	3.00%	6.11%	0.0028%
Ford Motor Co	F	44,858.97	0.14%	0.00%	9.50%	9.50%	0.0129%
Diamondback Energy Inc	FANG	10,866.39	0.03%	2.18%	-3.00%	-0.85%	-0.0003%
Fastenal Co	FAST	26,951.65	0.08%	2.39%	8.00%	10.49%	0.0085%

Company	Ticker	[2] Market Capitalization	[3] Weight in Index	[4] Estimated Dividend Yield	[5] Long-Term Growth Est.	[6] DCF Result	[7] Weighted DCF Result
Facebook Inc	FB	779,400.90	2.36%	0.00%	15.50%	15.50%	0.3650%
Fortune Brands Home & Security Inc	FBHS	11,911.77	0.04%	1.21%	8.50%	9.76%	0.0035%
Freeport-McMoRan Inc	FCX	54,025.30	0.16%	0.88%	23.00%	23.98%	0.0391%
FedEx Corp	FDX	68,677.25	0.21%	1.00%	8.50%	9.54%	0.0198%
FirstEnergy Corp	FE	17,352.59	0.05%	4.88%	8.50%	13.59%	0.0071%
F5 Networks Inc	FFIV	12,581.56	0.04%	0.00%	7.00%	7.00%	0.0027%
Fidelity National Information Services I	FIS	82,453.80	0.25%	1.17%	28.00%	29.33%	0.0731%
Fiserv Inc	FISV	74,450.23	0.22%	0.00%	14.00%	14.00%	0.0315%
Fifth Third Bancorp	FITB	23,884.36	0.07%	3.22%	1.00%	4.24%	0.0031%
FLIR Systems Inc	FLIR	7,274.56	0.02%	1.23%	8.00%	9.28%	0.0020%
Flowserve Corp	FLS	5,095.41	0.02%	2.04%	9.50%	11.64%	0.0018%
FleetCor Technologies Inc	FLT	22,683.15	0.07%	0.00%	14.00%	14.00%	0.0096%
FMC Corp	FMC	13,851.56	0.04%	1.84%	11.50%	13.45%	0.0056%
Fox Corp	FOX	N/A	N/A	0.00%	N/A	N/A	N/A
First Republic Bank/CA	FRC	28,092.47	0.08%	0.52%	10.50%	11.05%	0.0094%
Federal Realty Investment Trust	FRT	7,721.80	0.02%	4.17%	-0.50%	3.66%	0.0009%
Fortinet Inc	FTNT	26,979.13	0.08%	0.00%	21.00%	21.00%	0.0171%
Fortive Corp	FTV	22,794.72	0.07%	0.41%	7.00%	7.42%	0.0051%
General Dynamics Corp	GD	47,087.56	0.14%	2.68%	5.00%	7.75%	0.0110%
General Electric Co	GE	103,892.10	0.31%	0.34%	4.00%	4.35%	0.0136%
Gilead Sciences Inc	GILD	81,570.30	0.25%	4.36%	3.50%	7.94%	0.0196%
General Mills Inc	GIS	34,733.63	0.10%	3.66%	4.00%	7.73%	0.0081%
Globe Life Inc	GL	9,946.89	0.03%	0.79%	8.00%	8.82%	0.0027%
Corning Inc	GLW	28,834.29	0.09%	2.53%	13.50%	16.20%	0.0141%
General Motors Co	GM	75,701.88	0.23%	0.00%	7.00%	7.00%	0.0160%
Alphabet Inc	GOOG	1,442,407.00	4.36%	0.00%	14.50%	14.50%	0.6320%
Genuine Parts Co	GPC	14,276.05	0.04%	3.30%	7.00%	10.42%	0.0045%
Global Payments Inc	GPN	57,717.50	0.17%	0.40%	11.50%	11.92%	0.0208%
Gap Inc/The	GPS	8,583.30	0.03%	0.00%	2.50%	2.50%	0.0006%
Garmin Ltd	GRMN	24,767.11	0.07%	2.01%	10.50%	12.62%	0.0094%
Goldman Sachs Group Inc/The	GS	107,604.40	0.33%	1.60%	6.50%	8.15%	0.0265%
WW Grainger Inc	GWW	19,974.16	0.06%	1.68%	7.50%	9.24%	0.0056%
Halliburton Co	HAL	18,145.65	0.05%	0.88%	1.50%	2.39%	0.0013%
Hasbro Inc	HAS	12,453.29	0.04%	2.99%	9.00%	12.12%	0.0046%
Huntington Bancshares Inc/OH	HBAN	15,229.14	0.05%	4.01%	2.50%	6.56%	0.0030%
Hanesbrands Inc	HBI	6,223.91	0.02%	3.36%	3.50%	6.92%	0.0013%
HCA Healthcare Inc	HCA	59,702.00	0.18%	0.61%	11.00%	11.64%	0.0210%
Home Depot Inc/The	HD	302,269.90	0.91%	2.19%	8.50%	10.78%	0.0985%
Hess Corp	HES	18,983.50	N/A	1.62%	N/A	N/A	N/A
HollyFrontier Corp	HFC	5,461.56	0.02%	4.39%	-2.00%	2.35%	0.0004%
Hartford Financial Services Group Inc/Th	HIG	17,947.52	0.05%	2.79%	8.50%	11.41%	0.0062%
Huntington Ingalls Industries Inc	HII	7,226.01	0.02%	2.56%	7.50%	10.16%	0.0022%
Hilton Worldwide Holdings Inc	HLT	30,914.02	0.09%	0.00%	11.00%	11.00%	0.0103%
Hologic Inc	HOLX	21,240.04	0.06%	0.00%	25.50%	25.50%	0.0164%
Honeywell International Inc	HON	141,673.20	0.43%	1.84%	8.00%	9.91%	0.0424%
Hewlett Packard Enterprise Co	HPE	18,018.00	0.05%	3.43%	2.50%	5.97%	0.0033%
HP Inc	HPQ	34,269.12	0.10%	2.97%	10.00%	13.12%	0.0136%
Hormel Foods Corp	HRL	25,353.09	0.08%	2.09%	10.00%	12.19%	0.0093%
Henry Schein Inc	HSIC	9,241.12	0.03%	0.00%	4.50%	4.50%	0.0013%
Host Hotels & Resorts Inc	HST	11,171.84	0.03%	0.00%	-9.00%	-9.00%	-0.0030%
Hershey Co/The	HSY	31,487.54	0.10%	2.13%	5.00%	7.18%	0.0068%
Humana Inc	HUM	49,879.08	0.15%	0.73%	11.00%	11.77%	0.0177%
Howmet Aerospace Inc	HWM	12,418.42	0.04%	0.00%	3.50%	3.50%	0.0013%
International Business Machines Corp	IBM	106,900.10	0.32%	5.44%	-0.50%	4.93%	0.0159%
Intercontinental Exchange Inc	ICE	63,269.58	0.19%	1.17%	9.50%	10.73%	0.0205%
IDEXX Laboratories Inc	IDXX	46,091.85	0.14%	0.00%	14.00%	14.00%	0.0195%
IDEX Corp	IEX	14,640.21	0.04%	1.03%	7.50%	8.57%	0.0038%
International Flavors & Fragrances Inc	IFF	14,721.47	0.04%	2.27%	6.00%	8.34%	0.0037%
Illumina Inc	ILMN	72,159.04	0.22%	0.00%	8.50%	8.50%	0.0185%
Incyte Corp	INCY	18,337.51	0.06%	0.00%	62.00%	62.00%	0.0344%
IHS Markit Ltd	INFO	36,942.45	0.11%	0.86%	10.50%	11.41%	0.0127%
Intel Corp	INTC	251,234.70	0.76%	2.25%	7.00%	9.33%	0.0708%
Intuit Inc	INTU	109,236.20	0.33%	0.60%	15.50%	16.15%	0.0533%
International Paper Co	IP	19,065.35	0.06%	4.23%	6.50%	10.87%	0.0063%
Interpublic Group of Cos Inc/The	IPG	9,804.85	0.03%	4.29%	10.00%	14.50%	0.0043%
IPG Photonics Corp	IPGP	12,650.24	0.04%	0.00%	10.00%	10.00%	0.0038%
IQVIA Holdings Inc	IQV	36,217.88	0.11%	0.00%	11.00%	11.00%	0.0120%
Ingersoll Rand Inc	IR	17,951.94	N/A	0.00%	N/A	N/A	N/A
Iron Mountain Inc	IRM	9,434.46	0.03%	7.58%	7.50%	15.36%	0.0044%
Intuitive Surgical Inc	ISRG	91,657.05	0.28%	0.00%	13.00%	13.00%	0.0360%
Gartner Inc	IT	15,936.08	0.05%	0.00%	10.50%	10.50%	0.0051%
Illinois Tool Works Inc	ITW	62,742.96	0.19%	2.30%	9.00%	11.40%	0.0216%
Invesco Ltd	IVZ	10,371.79	0.03%	2.75%	2.50%	5.28%	0.0017%
Jacobs Engineering Group Inc	J	14,669.25	0.04%	0.75%	13.50%	14.30%	0.0063%
JB Hunt Transport Services Inc	JBHT	15,198.75	0.05%	0.80%	7.50%	8.33%	0.0038%
Johnson Controls International plc	JCI	39,759.01	0.12%	1.88%	8.00%	9.96%	0.0120%
Jack Henry & Associates Inc	JKHY	11,325.15	0.03%	1.24%	10.50%	11.81%	0.0040%
Johnson & Johnson	JNJ	436,044.80	1.32%	2.44%	9.50%	12.06%	0.1588%
Juniper Networks Inc	JNPR	7,930.34	0.02%	3.39%	5.50%	8.98%	0.0022%
JPMorgan Chase & Co	JPM	442,294.30	1.34%	2.48%	5.50%	8.05%	0.1076%
Kellogg Co	K	19,945.66	0.06%	3.96%	2.50%	6.51%	0.0039%
KeyCorp	KEY	19,250.76	0.06%	3.75%	4.50%	8.33%	0.0048%
Keysight Technologies Inc	KEYS	27,893.75	0.08%	0.00%	16.50%	16.50%	0.0139%
Kraft Heinz Co/The	KHC	45,275.46	0.14%	4.32%	-0.50%	3.81%	0.0052%
Kimco Realty Corp	KIM	7,690.63	0.02%	3.59%	5.00%	8.68%	0.0020%
KLA Corp	KLAC	50,919.38	0.15%	1.09%	13.00%	14.16%	0.0218%
Kimberly-Clark Corp	KMB	44,514.11	0.13%	3.49%	6.50%	10.10%	0.0136%
Kinder Morgan Inc	KMI	34,258.21	0.10%	6.94%	19.00%	26.60%	0.0275%
CarMax Inc	KMX	19,973.29	0.06%	0.00%	8.50%	8.50%	0.0051%
Coca-Cola Co/The	KO	215,408.60	0.65%	3.35%	6.50%	9.96%	0.0648%
Kroger Co/The	KR	26,327.42	0.08%	2.10%	7.50%	9.68%	0.0077%
Kansas City Southern	KSU	19,665.25	0.06%	1.03%	13.00%	14.10%	0.0084%
Loews Corp	L	13,344.89	0.04%	0.52%	13.00%	13.55%	0.0055%

Company	Ticker	[2] Market Capitalization	[3] Weight in Index	[4] Estimated Dividend Yield	[5] Long-Term Growth Est.	[6] DCF Result	[7] Weighted DCF Result
L Brands Inc	LB	13,505.24	0.04%	0.00%	16.00%	16.00%	0.0065%
Leidos Holdings Inc	LDOS	14,978.16	0.05%	1.29%	10.50%	11.86%	0.0054%
Leggett & Platt Inc	LEG	5,532.67	0.02%	3.83%	8.00%	11.98%	0.0020%
Lennar Corp	LEN	27,286.30	0.08%	1.15%	9.50%	10.70%	0.0088%
Laboratory Corp of America Holdings	LH	23,663.33	0.07%	0.00%	9.50%	9.50%	0.0068%
L3Harris Technologies Inc	LHX	40,876.22	N/A	1.80%	N/A	N/A	N/A
Linde PLC	LIN	130,836.40	N/A	1.74%	N/A	N/A	N/A
LKQ Corp	LKQ	11,193.40	0.03%	0.00%	10.00%	10.00%	0.0034%
Eli Lilly and Co	LLY	197,477.10	0.60%	1.65%	10.00%	11.73%	0.0700%
Lockheed Martin Corp	LMT	94,287.21	0.28%	3.09%	8.50%	11.72%	0.0334%
Lincoln National Corp	LNC	10,536.26	0.03%	3.14%	9.50%	12.79%	0.0041%
Alliant Energy Corp	LNT	12,045.97	0.04%	3.34%	5.50%	8.93%	0.0033%
Lowe's Cos Inc	LOW	133,201.80	0.40%	1.36%	14.50%	15.96%	0.0642%
Lam Research Corp	LRCX	83,905.24	0.25%	0.89%	12.50%	13.45%	0.0341%
Lumen Technologies Inc	LUMN	12,914.48	0.04%	8.50%	2.50%	11.11%	0.0043%
Southwest Airlines Co	LUV	30,953.92	0.09%	0.00%	1.50%	1.50%	0.0014%
Las Vegas Sands Corp	LVS	44,304.36	0.13%	0.00%	5.50%	5.50%	0.0074%
Lamb Weston Holdings Inc	LW	11,282.51	0.03%	1.23%	4.00%	5.25%	0.0018%
LyondellBasell Industries NV	LYB	32,660.52	N/A	4.29%	N/A	N/A	N/A
Live Nation Entertainment Inc	LYV	18,424.55	N/A	0.00%	N/A	N/A	N/A
Mastercard Inc	MA	336,655.30	1.02%	0.52%	12.00%	12.55%	0.1277%
Mid-America Apartment Communities Inc	MAA	15,733.96	0.05%	2.98%	1.00%	3.99%	0.0019%
Marriott International Inc/MD	MAR	42,597.77	0.13%	0.00%	4.00%	4.00%	0.0051%
Masco Corp	MAS	14,124.31	0.04%	1.03%	9.00%	10.08%	0.0043%
McDonald's Corp	MCD	159,044.00	0.48%	2.45%	8.00%	10.55%	0.0507%
Microchip Technology Inc	MCHP	43,902.52	0.13%	0.96%	9.00%	10.00%	0.0133%
McKesson Corp	MCK	29,187.69	0.09%	0.93%	9.00%	9.97%	0.0088%
Moody's Corp	MCO	52,697.95	0.16%	0.88%	9.00%	9.92%	0.0158%
Mondelez International Inc	MDLZ	78,526.98	0.24%	2.40%	8.00%	10.50%	0.0249%
Medtronic PLC	MDT	158,990.00	0.48%	2.03%	7.00%	9.10%	0.0437%
MetLife Inc	MET	50,177.75	0.15%	3.32%	6.50%	9.93%	0.0151%
MGM Resorts International	MGM	17,246.01	0.05%	0.03%	30.00%	30.03%	0.0157%
Mohawk Industries Inc	MHK	11,993.47	N/A	0.00%	N/A	N/A	N/A
McCormick & Co Inc/MD	MKC	22,933.52	0.07%	1.58%	6.50%	8.13%	0.0056%
MarketAxess Holdings Inc	MKTX	20,338.23	0.06%	0.49%	17.00%	17.53%	0.0108%
Martin Marietta Materials Inc	MLM	20,266.19	0.06%	0.71%	8.50%	9.24%	0.0057%
Marsh & McLennan Cos Inc	MMC	59,665.52	0.18%	1.62%	9.00%	10.69%	0.0193%
3M Co	MMM	101,895.40	0.31%	3.35%	5.00%	8.43%	0.0260%
Monster Beverage Corp	MNST	48,650.62	0.15%	0.00%	12.50%	12.50%	0.0184%
Altria Group Inc	MO	81,027.06	0.24%	7.89%	6.50%	14.65%	0.0359%
Mosaic Co/The	MOS	11,535.71	0.03%	0.82%	21.00%	21.91%	0.0076%
Marathon Petroleum Corp	MPC	33,780.39	0.10%	4.47%	3.50%	8.05%	0.0082%
Monolithic Power Systems Inc	MPWR	17,149.11	0.05%	0.63%	21.50%	22.20%	0.0115%
Merck & Co Inc	MRK	191,098.00	0.58%	3.44%	9.00%	12.59%	0.0727%
Marathon Oil Corp	MRO	7,568.20	0.02%	1.25%	13.00%	14.33%	0.0033%
Morgan Stanley	MS	118,942.90	0.36%	1.86%	7.50%	9.43%	0.0339%
MSCI Inc	MSCI	36,482.01	0.11%	0.78%	18.00%	18.85%	0.0208%
Microsoft Corp	MSFT	1,842,733.00	5.57%	0.92%	14.50%	15.49%	0.8623%
Motorola Solutions Inc	MSI	30,795.23	0.09%	1.56%	8.00%	9.62%	0.0090%
M&T Bank Corp	MTB	19,014.51	0.06%	2.97%	4.00%	7.03%	0.0040%
Mettler-Toledo International Inc	MTD	27,379.15	0.08%	0.00%	12.00%	12.00%	0.0099%
Micron Technology Inc	MU	96,117.85	0.29%	0.00%	11.50%	11.50%	0.0334%
Maxim Integrated Products Inc	MXIM	25,631.90	0.08%	0.00%	7.00%	7.00%	0.0054%
Norwegian Cruise Line Holdings Ltd	NCLH	7,020.02	0.02%	0.00%	-4.50%	-4.50%	-0.0010%
Nasdaq Inc	NDAQ	23,732.20	0.07%	1.36%	7.00%	8.41%	0.0060%
NextEra Energy Inc	NEE	158,058.20	0.48%	1.91%	10.50%	12.51%	0.0597%
Newmont Corp	NEM	45,783.37	0.14%	2.81%	19.50%	22.58%	0.0312%
Netflix Inc	NFLX	243,579.20	0.74%	0.00%	24.00%	24.00%	0.1766%
NiSource Inc	NI	8,685.19	0.03%	3.88%	12.50%	16.62%	0.0044%
NIKE Inc	NKE	226,784.20	0.69%	0.76%	26.50%	27.36%	0.1875%
NortonLifeLock Inc	NLOK	12,415.05	0.04%	2.36%	6.50%	8.94%	0.0034%
Nielsen Holdings PLC	NLSN	8,332.36	N/A	1.03%	N/A	N/A	N/A
Northrop Grumman Corp	NOC	49,544.96	0.15%	1.95%	10.50%	12.55%	0.0188%
NOV Inc	NOV	5,594.94	N/A	0.00%	N/A	N/A	N/A
ServiceNow Inc	NOW	113,312.30	0.34%	0.00%	54.50%	54.50%	0.1866%
NRG Energy Inc	NRG	9,709.73	0.03%	3.27%	-1.50%	1.75%	0.0005%
Norfolk Southern Corp	NSC	64,265.82	0.19%	1.57%	9.50%	11.14%	0.0216%
NetApp Inc	NTAP	15,149.28	0.05%	2.93%	6.00%	9.02%	0.0041%
Northern Trust Corp	NTRS	20,283.47	0.06%	2.87%	4.50%	7.43%	0.0046%
Nucor Corp	NUE	17,209.90	0.05%	2.84%	3.00%	5.88%	0.0031%
NVIDIA Corp	NVDA	369,072.60	1.12%	0.11%	13.50%	13.62%	0.1519%
NVR Inc	NVR	17,490.96	0.05%	0.00%	9.50%	9.50%	0.0050%
Newell Brands Inc	NWL	10,217.14	0.03%	3.82%	4.50%	8.41%	0.0026%
News Corp	NWS	N/A	N/A	0.00%	N/A	N/A	N/A
Realty Income Corp	O	20,604.31	0.06%	4.66%	6.50%	11.31%	0.0070%
Old Dominion Freight Line Inc	ODFL	24,403.67	0.07%	0.39%	10.00%	10.41%	0.0077%
ONEOK Inc	OKE	20,437.63	0.06%	8.37%	9.50%	18.27%	0.0113%
Omnicom Group Inc	OMC	14,424.69	0.04%	3.88%	5.50%	9.49%	0.0041%
Oracle Corp	ORCL	183,289.70	0.55%	1.55%	10.50%	12.13%	0.0672%
O'Reilly Automotive Inc	ORLY	32,786.29	0.10%	0.00%	14.00%	14.00%	0.0139%
Otis Worldwide Corp	OTIS	27,157.31	N/A	1.28%	N/A	N/A	N/A
Occidental Petroleum Corp	OXY	24,895.92	0.08%	0.30%	12.00%	12.32%	0.0093%
Paycom Software Inc	PAYC	22,566.76	0.07%	0.00%	23.00%	23.00%	0.0157%
Paychex Inc	PAYX	32,161.07	0.10%	2.96%	6.50%	9.56%	0.0093%
People's United Financial Inc	PBCT	6,565.86	0.02%	4.66%	2.50%	7.22%	0.0014%
PACCAR Inc	PCAR	33,262.12	0.10%	3.44%	3.50%	7.00%	0.0070%
Healthpeak Properties Inc	PEAK	15,308.23	0.05%	3.96%	-15.00%	-11.34%	-0.0052%
Public Service Enterprise Group Inc	PEG	29,237.04	0.09%	3.52%	5.00%	8.61%	0.0076%
PepsiCo Inc	PEP	185,958.20	0.56%	3.04%	6.00%	9.13%	0.0513%
Pfizer Inc	PFE	193,883.70	0.59%	4.47%	8.50%	13.16%	0.0771%
Principal Financial Group Inc	PFG	14,897.11	0.05%	4.13%	4.50%	8.72%	0.0039%
Procter & Gamble Co/The	PG	316,329.70	0.96%	2.46%	8.00%	10.56%	0.1009%
Progressive Corp/The	PGR	50,508.00	0.15%	0.46%	9.50%	9.98%	0.0152%

Company	Ticker	[2] Market Capitalization	[3] Weight in Index	[4] Estimated Dividend Yield	[5] Long-Term Growth Est.	[6] DCF Result	[7] Weighted DCF Result
Parker-Hannifin Corp	PH	35,111.32	0.11%	1.29%	11.50%	12.86%	0.0136%
PulteGroup Inc	PHM	12,381.82	0.04%	1.21%	10.00%	11.27%	0.0042%
Packaging Corp of America	PKG	12,648.22	0.04%	3.00%	4.00%	7.06%	0.0027%
PerkinElmer Inc	PKI	16,157.42	0.05%	0.19%	17.50%	17.71%	0.0086%
Prologis Inc	PLD	66,863.08	0.20%	2.34%	6.00%	8.41%	0.0170%
Philip Morris International Inc	PM	134,884.20	0.41%	5.54%	5.00%	10.68%	0.0435%
PNC Financial Services Group Inc/The	PNC	71,041.20	0.21%	2.75%	3.00%	5.79%	0.0124%
Pentair PLC	PNR	9,129.07	0.03%	1.46%	5.50%	7.00%	0.0019%
Pinnacle West Capital Corp	PNW	8,688.94	0.03%	4.43%	4.50%	9.03%	0.0024%
Pool Corp	POOL	13,257.32	0.04%	0.70%	17.50%	18.26%	0.0073%
PPG Industries Inc	PPG	32,265.47	0.10%	1.58%	6.00%	7.63%	0.0074%
PPL Corp	PPL	21,583.22	0.07%	5.95%	2.50%	8.52%	0.0056%
Perrigo Co PLC	PRGO	6,012.83	0.02%	2.27%	3.50%	5.81%	0.0011%
Prudential Financial Inc	PRU	32,986.94	0.10%	5.51%	5.00%	10.65%	0.0106%
Public Storage	PSA	40,826.26	0.12%	3.42%	4.00%	7.49%	0.0092%
Phillips 66	PSX	35,223.55	0.11%	4.59%	3.00%	7.66%	0.0082%
PVH Corp	PVH	6,644.20	0.02%	0.00%	3.50%	3.50%	0.0007%
Quanta Services Inc	PWR	10,667.31	0.03%	0.31%	12.50%	12.83%	0.0041%
Pioneer Natural Resources Co	PXD	22,391.69	0.07%	1.65%	10.50%	12.24%	0.0083%
PayPal Holdings Inc	PYPL	348,318.40	1.05%	0.00%	19.00%	19.00%	0.2000%
QUALCOMM Inc	QCOM	164,436.00	0.50%	1.85%	15.50%	17.49%	0.0869%
Qorvo Inc	QRVO	19,783.14	0.06%	0.00%	66.00%	66.00%	0.0395%
Royal Caribbean Cruises Ltd	RCL	16,126.34	0.05%	0.00%	-0.50%	-0.50%	-0.0002%
Everest Re Group Ltd	RE	9,700.79	0.03%	2.55%	10.50%	13.18%	0.0039%
Regency Centers Corp	REG	8,916.45	0.03%	4.47%	14.50%	19.29%	0.0052%
Regeneron Pharmaceuticals Inc	REGN	51,358.65	0.16%	0.00%	10.50%	10.50%	0.0163%
Regions Financial Corp	RF	19,224.11	0.06%	3.10%	8.50%	11.73%	0.0068%
Robert Half International Inc	RHI	8,734.77	0.03%	1.99%	6.00%	8.05%	0.0021%
Raymond James Financial Inc	RJF	16,059.60	0.05%	1.33%	6.00%	7.37%	0.0036%
Ralph Lauren Corp	RL	8,144.07	0.02%	0.00%	6.50%	6.50%	0.0016%
ResMed Inc	RMD	29,061.52	0.09%	0.78%	13.00%	13.83%	0.0121%
Rockwell Automation Inc	ROK	28,808.13	0.09%	1.75%	7.00%	8.81%	0.0077%
Rollins Inc	ROL	17,993.40	0.05%	0.87%	11.50%	12.42%	0.0068%
Roper Technologies Inc	ROP	40,598.05	0.12%	0.58%	10.00%	10.61%	0.0130%
Ross Stores Inc	ROST	42,584.96	0.13%	0.00%	7.50%	7.50%	0.0097%
Republic Services Inc	RSG	31,924.35	0.10%	1.94%	8.50%	10.52%	0.0102%
Raytheon Technologies Corp	RTX	110,957.40	0.34%	2.63%	-6.00%	-3.45%	-0.0116%
SBA Communications Corp	SBAC	28,926.14	0.09%	0.88%	30.50%	31.51%	0.0275%
Starbucks Corp	SBUX	122,946.80	0.37%	1.82%	16.00%	17.97%	0.0667%
Charles Schwab Corp/The	SCHW	79,041.45	0.24%	1.22%	7.50%	8.77%	0.0209%
Sealed Air Corp	SEE	6,735.41	0.02%	1.47%	26.00%	27.66%	0.0056%
Sherwin-Williams Co/The	SHW	65,521.16	0.20%	0.78%	10.00%	10.82%	0.0214%
SVB Financial Group	SIVB	27,453.88	0.08%	0.00%	7.50%	7.50%	0.0062%
J M Smucker Co/The	SJM	13,171.36	0.04%	3.17%	2.50%	5.71%	0.0023%
Schlumberger NV	SLB	37,403.84	N/A	1.86%	N/A	N/A	N/A
SL Green Realty Corp	SLG	4,937.41	0.01%	6.10%	-1.50%	4.55%	0.0007%
Snap-on Inc	SNA	10,238.64	0.03%	2.61%	5.00%	7.68%	0.0024%
Synopsys Inc	SNPS	43,306.89	0.13%	0.00%	13.50%	13.50%	0.0177%
Southern Co/The	SO	62,603.46	0.19%	4.42%	3.50%	8.00%	0.0151%
Simon Property Group Inc	SPG	33,211.57	0.10%	4.81%	-1.00%	3.79%	0.0038%
S&P Global Inc	SPGI	81,546.55	0.25%	0.91%	10.00%	10.96%	0.0270%
Sempra Energy	SRE	35,887.68	0.11%	3.61%	11.00%	14.81%	0.0161%
STERIS PLC	STE	15,787.34	0.05%	0.87%	10.00%	10.91%	0.0052%
State Street Corp	STT	26,516.30	0.08%	2.77%	5.00%	7.84%	0.0063%
Seagate Technology PLC	STX	17,120.55	0.05%	3.75%	2.50%	6.30%	0.0033%
Constellation Brands Inc	STZ	44,156.29	0.13%	1.40%	7.50%	8.95%	0.0119%
Stanley Black & Decker Inc	SWK	30,156.65	0.09%	1.67%	6.00%	7.72%	0.0070%
Skyworks Solutions Inc	SWKS	31,675.64	0.10%	1.04%	11.50%	12.60%	0.0121%
Synchrony Financial	SYF	21,873.71	0.07%	2.35%	4.50%	6.90%	0.0046%
Stryker Corp	SYK	92,661.01	0.28%	1.02%	9.50%	10.57%	0.0296%
Sysco Corp	SYY	38,193.75	0.12%	2.40%	11.50%	14.04%	0.0162%
AT&T Inc	T	210,687.60	0.64%	7.17%	5.50%	12.87%	0.0819%
Molson Coors Beverage Co	TAP	9,833.85	0.03%	0.00%	5.50%	5.50%	0.0016%
TransDigm Group Inc	TDG	31,173.57	0.09%	0.00%	10.50%	10.50%	0.0099%
Teledyne Technologies Inc	TDY	14,868.26	0.04%	0.00%	8.00%	8.00%	0.0036%
TE Connectivity Ltd	TEL	42,949.18	0.13%	1.48%	5.50%	7.02%	0.0091%
Teradyne Inc	TER	23,129.79	0.07%	0.29%	14.50%	14.81%	0.0104%
Truist Financial Corp	TFC	75,022.77	0.23%	3.24%	7.00%	10.35%	0.0235%
Teleflex Inc	TFX	18,780.47	0.06%	0.34%	13.50%	13.86%	0.0079%
Target Corp	TGT	96,946.17	0.29%	1.41%	12.50%	14.00%	0.0410%
TJX Cos Inc/The	TJX	80,238.17	0.24%	1.56%	11.50%	13.15%	0.0319%
Thermo Fisher Scientific Inc	TMO	197,557.20	0.60%	0.18%	17.50%	17.70%	0.1056%
T-Mobile US Inc	TMUS	150,467.70	0.45%	0.00%	9.50%	9.50%	0.0432%
Tapestry Inc	TPR	10,736.97	0.03%	0.00%	4.00%	4.00%	0.0013%
Trimble Inc	TRMB	18,134.49	0.05%	0.00%	14.50%	14.50%	0.0079%
T Rowe Price Group Inc	TROW	36,953.45	0.11%	2.65%	8.00%	10.76%	0.0120%
Travelers Cos Inc/The	TRV	37,602.39	0.11%	2.29%	9.50%	11.90%	0.0135%
Tractor Supply Co	TSCO	19,833.61	0.06%	1.22%	10.50%	11.78%	0.0071%
Tesla Inc	TSLA	756,646.30	N/A	0.00%	N/A	N/A	N/A
Tyson Foods Inc	TSN	24,535.30	0.07%	2.65%	6.50%	9.24%	0.0068%
Trane Technologies PLC	TT	36,131.65	N/A	1.56%	N/A	N/A	N/A
Take-Two Interactive Software Inc	TTWO	22,548.21	0.07%	0.00%	16.50%	16.50%	0.0112%
Twitter Inc	TWTR	57,033.34	0.17%	0.00%	29.00%	29.00%	0.0500%
Texas Instruments Inc	TXN	163,826.50	0.50%	2.29%	4.50%	6.84%	0.0339%
Textron Inc	TXT	11,617.96	0.04%	0.16%	8.50%	8.67%	0.0030%
Tyler Technologies Inc	TYL	22,582.87	0.07%	0.00%	10.50%	10.50%	0.0072%
Under Armour Inc	UA	N/A	N/A	0.00%	N/A	N/A	N/A
United Airlines Holdings Inc	UAL	13,408.82	0.04%	0.00%	1.50%	1.50%	0.0006%
UDR Inc	UDR	12,459.30	0.04%	3.55%	3.50%	7.11%	0.0027%
Universal Health Services Inc	UHS	10,964.38	0.03%	0.00%	11.50%	11.50%	0.0038%
Ulta Beauty Inc	ULTA	18,282.55	0.06%	0.00%	7.00%	7.00%	0.0039%
UnitedHealth Group Inc	UNH	310,190.10	0.94%	1.53%	12.50%	14.13%	0.1324%
Unum Group	UNM	5,250.56	0.02%	4.42%	3.50%	8.00%	0.0013%

Company	Ticker	[2] Market Capitalization	[3] Weight in Index	[4] Estimated Dividend Yield	[5] Long-Term Growth Est.	[6] DCF Result	[7] Weighted DCF Result
Union Pacific Corp	UNP	142,587.20	0.43%	1.84%	10.00%	11.93%	0.0514%
United Parcel Service Inc	UPS	139,039.60	0.42%	2.60%	8.00%	10.70%	0.0450%
United Rentals Inc	URI	20,057.05	0.06%	0.00%	7.00%	7.00%	0.0042%
US Bancorp	USB	74,265.08	0.22%	3.41%	0.50%	3.92%	0.0088%
Visa Inc	V	405,059.50	1.22%	0.63%	15.50%	16.18%	0.1980%
Varian Medical Systems Inc	VAR	15,997.14	0.05%	0.00%	14.50%	14.50%	0.0070%
VF Corp	VFC	31,091.21	0.09%	2.47%	6.00%	8.54%	0.0080%
ViacomCBS Inc	VIAC	37,576.00	0.11%	1.57%	8.00%	9.63%	0.0109%
Valero Energy Corp	VLO	27,777.90	0.08%	5.76%	2.00%	7.82%	0.0066%
Vulcan Materials Co	VMC	21,441.65	0.06%	0.91%	12.50%	13.47%	0.0087%
Vornado Realty Trust	VNO	7,103.43	0.02%	5.71%	-20.00%	-14.86%	-0.0032%
Vontier Corp	VNT	N/A	N/A	0.00%	N/A	N/A	N/A
Verisk Analytics Inc	VRSK	30,688.33	0.09%	0.61%	11.50%	12.15%	0.0113%
VeriSign Inc	VRSN	22,750.71	0.07%	0.00%	9.50%	9.50%	0.0065%
Vertex Pharmaceuticals Inc	VRTX	55,898.39	0.17%	0.00%	32.00%	32.00%	0.0540%
Ventas Inc	VTR	18,879.15	0.06%	3.56%	1.50%	5.09%	0.0029%
Viatris Inc	VTRS	N/A	N/A	0.00%	N/A	N/A	N/A
Verizon Communications Inc	VZ	235,830.00	0.71%	4.40%	4.00%	8.49%	0.0605%
Westinghouse Air Brake Technologies Corp	WAB	15,100.31	0.05%	0.61%	8.50%	9.14%	0.0042%
Waters Corp	WAT	17,526.74	0.05%	0.00%	11.50%	11.50%	0.0061%
Walgreens Boots Alliance Inc	WBA	42,814.98	0.13%	3.77%	5.00%	8.86%	0.0115%
Western Digital Corp	WDC	20,593.80	0.06%	0.00%	6.00%	6.00%	0.0037%
WEC Energy Group Inc	WEC	25,875.13	0.08%	3.30%	6.00%	9.40%	0.0073%
Welltower Inc	WELL	27,606.39	0.08%	3.63%	3.50%	7.19%	0.0060%
Wells Fargo & Co	WFC	151,208.80	N/A	1.09%	N/A	N/A	N/A
Whirlpool Corp	WHR	12,026.14	0.04%	2.58%	6.50%	9.16%	0.0033%
Willis Towers Watson PLC	WLTW	29,626.16	0.09%	1.24%	11.50%	12.81%	0.0115%
Waste Management Inc	WM	47,418.49	0.14%	1.94%	6.00%	8.00%	0.0115%
Williams Cos Inc/The	WMB	28,008.17	0.08%	7.10%	12.00%	19.53%	0.0165%
Walmart Inc	WMT	416,723.30	1.26%	1.50%	8.00%	9.56%	0.1204%
W R Berkley Corp	WRB	12,097.44	0.04%	0.71%	10.00%	10.75%	0.0039%
Westrock Co	WRK	11,585.20	0.04%	1.82%	6.50%	8.38%	0.0029%
West Pharmaceutical Services Inc	WST	21,725.86	0.07%	0.23%	15.50%	15.75%	0.0103%
Western Union Co/The	WU	9,810.57	0.03%	3.77%	6.00%	9.88%	0.0029%
Weyerhaeuser Co	WY	25,496.96	0.08%	1.99%	20.50%	22.69%	0.0175%
Wynn Resorts Ltd	WYNN	13,178.72	0.04%	0.00%	10.00%	10.00%	0.0040%
Xcel Energy Inc	XEL	32,000.09	0.10%	2.99%	6.00%	9.08%	0.0088%
Xilinx Inc	XLNX	34,161.41	0.10%	1.09%	7.50%	8.63%	0.0089%
Exxon Mobil Corp	XOM	223,449.80	0.68%	6.59%	2.50%	9.17%	0.0619%
DENTSPLY SIRONA Inc	XRAY	11,512.77	0.03%	0.76%	5.50%	6.28%	0.0022%
Xerox Holdings Corp	XRX	4,827.63	0.01%	4.27%	5.00%	9.38%	0.0014%
Xylem Inc/NY	XYL	17,684.02	0.05%	1.14%	8.50%	9.69%	0.0052%
Yum! Brands Inc	YUM	31,510.68	0.10%	1.92%	9.50%	11.51%	0.0110%
Zimmer Biomet Holdings Inc	ZBH	32,873.63	0.10%	0.63%	5.50%	6.15%	0.0061%
Zebra Technologies Corp	ZBRA	25,639.31	0.08%	0.00%	10.00%	10.00%	0.0077%
Zions Bancorp NA	ZION	8,305.42	0.03%	2.69%	6.50%	9.28%	0.0023%
Zoetis Inc	ZTS	80,268.54	0.24%	0.59%	12.00%	12.63%	0.0306%
Total Market Capitalization:		33,095,519.92					14.34%

Notes:
[1] Equals sum of Col. [7]
[2] Source: Value Line
[3] Equals weight in S&P 500 based on market capitalization
[4] Source: Value Line
[5] Source: Value Line
[6] Equals ([4] x (1 + (0.5 x [5]))) + [5]
[7] Equals Col. [3] x Col. [6]

Ex Ante Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Using *Value Line* -derived Expected Market Required Return and Beta Coefficients

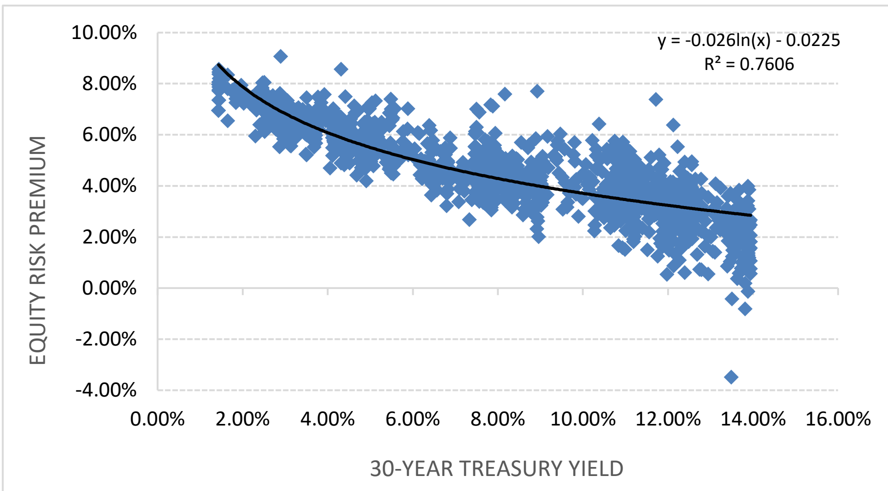
		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Current 30-Year Treasury Yield	Value Line Beta Coefficient	Value Line Proj. Market Required Return	Traditional CAPM	Empirical CAPM
ALLETE, Inc.	ALE	1.97%	0.85	14.34%	12.48%	12.95%
Alliant Energy Corporation	LNT	1.97%	0.85	14.34%	12.48%	12.95%
Ameren Corporation	AEE	1.97%	0.85	14.34%	12.48%	12.95%
American Electric Power Company, Inc.	AEP	1.97%	0.75	14.34%	11.24%	12.02%
Avista Corporation	AVA	1.97%	0.95	14.34%	13.72%	13.87%
CMS Energy Corporation	CMS	1.97%	0.80	14.34%	11.86%	12.48%
Consolidated Edison, Inc.	ED	1.97%	0.75	14.34%	11.24%	12.02%
DTE Energy Company	DTE	1.97%	0.95	14.34%	13.72%	13.87%
Duke Energy Corporation	DUK	1.97%	0.85	14.34%	12.48%	12.95%
Entergy Corporation	ETR	1.97%	0.95	14.34%	13.72%	13.87%
Evergy, Inc	EVRG	1.97%	1.00	14.34%	14.34%	14.34%
Eversource Energy	ES	1.97%	0.90	14.34%	13.10%	13.41%
Hawaiian Electric Industries, Inc.	HE	1.97%	0.80	14.34%	11.86%	12.48%
IDACORP, Inc.	IDA	1.97%	0.80	14.34%	11.86%	12.48%
NextEra Energy, Inc.	NEE	1.97%	0.90	14.34%	13.10%	13.41%
NorthWestern Corporation	NWE	1.97%	0.95	14.34%	13.72%	13.87%
OGE Energy Corp.	OGE	1.97%	1.10	14.34%	15.57%	15.27%
Otter Tail Corporation	OTTR	1.97%	0.85	14.34%	12.48%	12.95%
Pinnacle West Capital Corporation	PNW	1.97%	0.90	14.34%	13.10%	13.41%
Portland General Electric Company	POR	1.97%	0.85	14.34%	12.48%	12.95%
Public Service Enterprise Group Incorporated	PEG	1.97%	0.90	14.34%	13.10%	13.41%
Southern Company	SO	1.97%	0.95	14.34%	13.72%	13.87%
WEC Energy Group, Inc.	WEC	1.97%	0.80	14.34%	11.86%	12.48%
Xcel Energy Inc.	XEL	1.97%	0.80	14.34%	11.86%	12.48%
				Mean:	12.82%	13.20%
				Median:	12.48%	12.95%

		[6]	[7]	[8]	[9]	[10]
Company	Ticker	Projected 30-Year Treasury Yield	Value Line Beta Coefficient	Value Line Proj. Market Required Return	Traditional CAPM	Empirical CAPM
ALLETE, Inc.	ALE	2.72%	0.85	14.34%	12.59%	13.03%
Alliant Energy Corporation	LNT	2.72%	0.85	14.34%	12.59%	13.03%
Ameren Corporation	AEE	2.72%	0.85	14.34%	12.59%	13.03%
American Electric Power Company, Inc.	AEP	2.72%	0.75	14.34%	11.43%	12.16%
Avista Corporation	AVA	2.72%	0.95	14.34%	13.76%	13.90%
CMS Energy Corporation	CMS	2.72%	0.80	14.34%	12.01%	12.59%
Consolidated Edison, Inc.	ED	2.72%	0.75	14.34%	11.43%	12.16%
DTE Energy Company	DTE	2.72%	0.95	14.34%	13.76%	13.90%
Duke Energy Corporation	DUK	2.72%	0.85	14.34%	12.59%	13.03%
Entergy Corporation	ETR	2.72%	0.95	14.34%	13.76%	13.90%
Evergy, Inc	EVRG	2.72%	1.00	14.34%	14.34%	14.34%
Eversource Energy	ES	2.72%	0.90	14.34%	13.18%	13.47%
Hawaiian Electric Industries, Inc.	HE	2.72%	0.80	14.34%	12.01%	12.59%
IDACORP, Inc.	IDA	2.72%	0.80	14.34%	12.01%	12.59%
NextEra Energy, Inc.	NEE	2.72%	0.90	14.34%	13.18%	13.47%
NorthWestern Corporation	NWE	2.72%	0.95	14.34%	13.76%	13.90%
OGE Energy Corp.	OGE	2.72%	1.10	14.34%	15.50%	15.21%
Otter Tail Corporation	OTTR	2.72%	0.85	14.34%	12.59%	13.03%
Pinnacle West Capital Corporation	PNW	2.72%	0.90	14.34%	13.18%	13.47%
Portland General Electric Company	POR	2.72%	0.85	14.34%	12.59%	13.03%
Public Service Enterprise Group Incorporated	PEG	2.72%	0.90	14.34%	13.18%	13.47%
Southern Company	SO	2.72%	0.95	14.34%	13.76%	13.90%
WEC Energy Group, Inc.	WEC	2.72%	0.80	14.34%	12.01%	12.59%
Xcel Energy Inc.	XEL	2.72%	0.80	14.34%	12.01%	12.59%
				Mean:	12.91%	13.27%
				Median:	12.59%	13.03%

Notes:
[1] Source: Bloomberg Professional Service; 30-day average
[2] Source: Value Line
[3] Exhibit JEN-5, pages 7-12
[4] Equals Col. [1] + ((Col. [2] x (Col. [3] - Col. [1]))
[5] Equals Col. [1] + ((0.75 x (Col. [2] x (Col. [3] - Col. [1])) + 0.25 x (Col. [3] - Col. [1]))
[6] Source: Blue Chip Financial Forecasts, Vol. 39, No. 12, December 1, 2020, at 14; Vol. 40, No. 3, March 1, 2021, at 2.
[7] See Note [2]
[8] See Note [3]
[9] See Note [4]
[10] See Note [5]

Bond Yield Plus Risk Premium

[1] Constant	[2] Slope	[3] 30-Year Treasury Yield	[4] Risk Premium	[5] Return on Equity
-2.25%	-2.59%			
Current 30-Year Treasury		1.97%	7.92%	9.89%
Projected 30-Year Treasury		2.72%	7.08%	9.80%



Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Sources: Current = Bloomberg Professional Service,
Projected = Average of near-term and long-term projected 30-year Treasury yield.
Source: Blue Chip Financial Forecasts, Vol. 39, No. 12, December 1, 2020, at 14; Vol. 40, No. 3, March 1, 2021, at 2.
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]
[6] Source: SNL Financial
[7] Source: SNL Financial
[8] Source: Bloomberg Professional Service, equals 200-trading day average (i.e. lag period)
[9] Equals [7] - [8]

Bond Yield Plus Risk Premium

[6] Date of Electric Rate Case	[7] Return on Equity	[8] 30-Year Treasury Yield	[9] Risk Premium
1/1/1980	14.50%	9.36%	5.14%
1/7/1980	14.39%	9.39%	5.00%
1/9/1980	15.00%	9.40%	5.60%
1/14/1980	15.17%	9.42%	5.75%
1/17/1980	13.93%	9.44%	4.49%
1/23/1980	15.50%	9.47%	6.03%
1/30/1980	13.86%	9.52%	4.34%
1/31/1980	12.61%	9.53%	3.08%
2/6/1980	13.71%	9.58%	4.13%
2/13/1980	12.80%	9.64%	3.16%
2/14/1980	13.00%	9.65%	3.35%
2/19/1980	13.50%	9.68%	3.82%
2/27/1980	13.75%	9.78%	3.97%
2/29/1980	13.75%	9.81%	3.94%
2/29/1980	14.00%	9.81%	4.19%
2/29/1980	14.77%	9.81%	4.96%
3/7/1980	12.70%	9.90%	2.80%
3/14/1980	13.50%	9.97%	3.53%
3/26/1980	14.16%	10.11%	4.05%
3/27/1980	14.24%	10.12%	4.12%
3/28/1980	14.50%	10.14%	4.36%
4/11/1980	12.75%	10.28%	2.47%
4/14/1980	13.85%	10.29%	3.56%
4/16/1980	15.50%	10.32%	5.18%
4/22/1980	13.90%	10.36%	3.54%
4/22/1980	13.25%	10.36%	2.89%
4/24/1980	16.80%	10.38%	6.42%
4/29/1980	15.50%	10.41%	5.09%
5/6/1980	13.70%	10.45%	3.25%
5/7/1980	15.00%	10.46%	4.54%
5/8/1980	13.75%	10.47%	3.28%
5/9/1980	14.35%	10.47%	3.88%
5/13/1980	13.60%	10.49%	3.11%
5/15/1980	13.25%	10.50%	2.75%
5/19/1980	13.75%	10.52%	3.23%
5/27/1980	14.60%	10.55%	4.05%
5/27/1980	13.62%	10.55%	3.07%
5/29/1980	16.00%	10.56%	5.44%
5/30/1980	13.80%	10.57%	3.23%
6/2/1980	15.63%	10.58%	5.05%
6/9/1980	15.90%	10.61%	5.29%
6/10/1980	13.78%	10.61%	3.17%
6/12/1980	14.25%	10.62%	3.63%
6/19/1980	13.40%	10.63%	2.77%
6/30/1980	13.00%	10.65%	2.35%
6/30/1980	13.40%	10.65%	2.75%
7/9/1980	14.75%	10.68%	4.07%
7/10/1980	15.00%	10.69%	4.31%
7/15/1980	15.80%	10.70%	5.10%
7/18/1980	13.80%	10.72%	3.08%
7/22/1980	14.10%	10.73%	3.37%
7/24/1980	15.00%	10.73%	4.27%
7/25/1980	13.48%	10.74%	2.74%
7/31/1980	14.58%	10.76%	3.82%
8/8/1980	14.00%	10.78%	3.22%
8/8/1980	13.50%	10.78%	2.72%
8/8/1980	15.45%	10.78%	4.67%
8/11/1980	14.85%	10.78%	4.07%
8/14/1980	14.00%	10.79%	3.21%
8/14/1980	16.25%	10.79%	5.46%
8/25/1980	13.75%	10.82%	2.93%
8/27/1980	13.80%	10.83%	2.97%
8/29/1980	12.50%	10.84%	1.66%
9/15/1980	15.80%	10.88%	4.92%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
9/15/1980	13.93%	10.88%	3.05%
9/15/1980	13.50%	10.88%	2.62%
9/24/1980	12.50%	10.93%	1.57%
9/24/1980	15.00%	10.93%	4.07%
9/26/1980	13.75%	10.95%	2.80%
9/30/1980	14.20%	10.96%	3.24%
9/30/1980	14.10%	10.96%	3.14%
10/1/1980	13.90%	10.97%	2.93%
10/3/1980	15.50%	10.99%	4.51%
10/7/1980	12.50%	11.00%	1.50%
10/9/1980	14.50%	11.01%	3.49%
10/9/1980	14.50%	11.01%	3.49%
10/9/1980	13.25%	11.01%	2.24%
10/16/1980	16.10%	11.03%	5.07%
10/17/1980	14.50%	11.03%	3.47%
10/31/1980	14.25%	11.11%	3.14%
10/31/1980	13.75%	11.11%	2.64%
11/4/1980	15.00%	11.12%	3.88%
11/5/1980	14.00%	11.13%	2.87%
11/5/1980	13.75%	11.13%	2.62%
11/8/1980	13.75%	11.15%	2.60%
11/10/1980	14.85%	11.15%	3.70%
11/17/1980	14.00%	11.18%	2.82%
11/18/1980	14.00%	11.19%	2.81%
11/19/1980	13.00%	11.19%	1.81%
11/24/1980	14.00%	11.20%	2.80%
11/26/1980	14.00%	11.21%	2.79%
12/8/1980	15.10%	11.22%	3.88%
12/8/1980	14.15%	11.22%	2.93%
12/9/1980	15.35%	11.22%	4.13%
12/12/1980	15.45%	11.22%	4.23%
12/17/1980	13.25%	11.23%	2.02%
12/18/1980	15.80%	11.23%	4.57%
12/19/1980	14.50%	11.23%	3.27%
12/19/1980	14.64%	11.23%	3.41%
12/22/1980	13.45%	11.22%	2.23%
12/22/1980	15.00%	11.22%	3.78%
12/30/1980	14.50%	11.21%	3.29%
12/30/1980	14.95%	11.21%	3.74%
12/31/1980	13.39%	11.21%	2.18%
1/2/1981	15.25%	11.21%	4.04%
1/7/1981	14.30%	11.21%	3.09%
1/19/1981	15.25%	11.19%	4.06%
1/23/1981	14.40%	11.20%	3.20%
1/23/1981	13.10%	11.20%	1.90%
1/26/1981	15.25%	11.20%	4.05%
1/27/1981	15.00%	11.20%	3.80%
1/31/1981	13.47%	11.21%	2.26%
2/3/1981	15.25%	11.23%	4.02%
2/5/1981	15.75%	11.25%	4.50%
2/11/1981	15.60%	11.28%	4.32%
2/20/1981	15.25%	11.34%	3.91%
3/11/1981	15.40%	11.50%	3.90%
3/12/1981	14.51%	11.51%	3.00%
3/12/1981	16.00%	11.51%	4.49%
3/13/1981	13.02%	11.52%	1.50%
3/18/1981	16.19%	11.55%	4.64%
3/19/1981	13.75%	11.56%	2.19%
3/23/1981	14.30%	11.58%	2.72%
3/25/1981	15.30%	11.61%	3.69%
4/1/1981	14.53%	11.69%	2.84%
4/3/1981	19.10%	11.72%	7.38%
4/9/1981	15.00%	11.79%	3.21%
4/9/1981	15.30%	11.79%	3.51%
4/9/1981	17.00%	11.79%	5.21%
4/9/1981	16.50%	11.79%	4.71%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
4/10/1981	13.75%	11.81%	1.94%
4/13/1981	13.57%	11.83%	1.74%
4/15/1981	15.30%	11.86%	3.44%
4/16/1981	13.50%	11.88%	1.62%
4/17/1981	14.10%	11.88%	2.22%
4/21/1981	16.80%	11.91%	4.89%
4/21/1981	14.00%	11.91%	2.09%
4/24/1981	16.00%	11.96%	4.04%
4/27/1981	13.61%	11.98%	1.63%
4/27/1981	12.50%	11.98%	0.52%
4/29/1981	13.65%	12.01%	1.64%
4/30/1981	13.50%	12.02%	1.48%
5/4/1981	16.22%	12.06%	4.16%
5/5/1981	14.40%	12.08%	2.32%
5/7/1981	16.25%	12.12%	4.13%
5/7/1981	16.27%	12.12%	4.15%
5/8/1981	13.00%	12.14%	0.86%
5/8/1981	16.00%	12.14%	3.86%
5/12/1981	13.50%	12.17%	1.33%
5/15/1981	15.75%	12.23%	3.52%
5/18/1981	14.88%	12.24%	2.64%
5/20/1981	16.00%	12.27%	3.73%
5/21/1981	14.00%	12.28%	1.72%
5/26/1981	14.90%	12.31%	2.59%
5/27/1981	15.00%	12.32%	2.68%
5/29/1981	15.50%	12.34%	3.16%
6/1/1981	16.50%	12.35%	4.15%
6/3/1981	14.67%	12.38%	2.29%
6/5/1981	13.00%	12.40%	0.60%
6/10/1981	16.75%	12.42%	4.33%
6/17/1981	14.40%	12.46%	1.94%
6/18/1981	16.33%	12.47%	3.86%
6/25/1981	14.75%	12.52%	2.23%
6/26/1981	16.00%	12.53%	3.47%
6/30/1981	15.25%	12.55%	2.70%
7/1/1981	15.50%	12.56%	2.94%
7/1/1981	17.50%	12.56%	4.94%
7/10/1981	16.00%	12.62%	3.38%
7/14/1981	16.90%	12.64%	4.26%
7/15/1981	16.00%	12.65%	3.35%
7/17/1981	15.00%	12.67%	2.33%
7/20/1981	15.00%	12.68%	2.32%
7/21/1981	14.00%	12.69%	1.31%
7/28/1981	13.48%	12.75%	0.73%
7/31/1981	13.50%	12.79%	0.71%
7/31/1981	16.00%	12.79%	3.21%
7/31/1981	15.00%	12.79%	2.21%
8/5/1981	15.71%	12.83%	2.88%
8/10/1981	14.50%	12.87%	1.63%
8/11/1981	15.00%	12.88%	2.12%
8/20/1981	16.50%	12.95%	3.55%
8/20/1981	13.50%	12.95%	0.55%
8/24/1981	15.00%	12.97%	2.03%
8/28/1981	15.00%	13.01%	1.99%
9/3/1981	14.50%	13.06%	1.44%
9/10/1981	14.50%	13.11%	1.39%
9/11/1981	16.00%	13.12%	2.88%
9/16/1981	16.00%	13.15%	2.85%
9/17/1981	16.50%	13.16%	3.34%
9/23/1981	15.85%	13.20%	2.65%
9/28/1981	15.50%	13.23%	2.27%
10/9/1981	15.75%	13.34%	2.41%
10/15/1981	16.25%	13.37%	2.88%
10/16/1981	16.50%	13.39%	3.11%
10/16/1981	15.50%	13.39%	2.11%
10/19/1981	14.25%	13.40%	0.85%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/20/1981	15.25%	13.41%	1.84%
10/20/1981	17.00%	13.41%	3.59%
10/23/1981	16.00%	13.46%	2.54%
10/27/1981	10.00%	13.49%	-3.49%
10/29/1981	16.50%	13.52%	2.98%
10/29/1981	14.75%	13.52%	1.23%
11/3/1981	15.17%	13.54%	1.63%
11/5/1981	16.60%	13.56%	3.04%
11/6/1981	15.17%	13.57%	1.60%
11/24/1981	15.50%	13.61%	1.89%
11/25/1981	16.10%	13.61%	2.49%
11/25/1981	16.10%	13.61%	2.49%
11/25/1981	15.25%	13.61%	1.64%
11/25/1981	15.35%	13.61%	1.74%
12/1/1981	16.50%	13.61%	2.89%
12/1/1981	15.70%	13.61%	2.09%
12/1/1981	16.49%	13.61%	2.88%
12/1/1981	16.00%	13.61%	2.39%
12/4/1981	16.00%	13.61%	2.39%
12/11/1981	16.25%	13.63%	2.62%
12/14/1981	14.00%	13.63%	0.37%
12/15/1981	15.81%	13.63%	2.18%
12/15/1981	16.00%	13.63%	2.37%
12/16/1981	15.25%	13.63%	1.62%
12/17/1981	16.50%	13.64%	2.86%
12/18/1981	15.45%	13.64%	1.81%
12/30/1981	16.00%	13.67%	2.33%
12/30/1981	16.25%	13.67%	2.58%
12/30/1981	14.25%	13.67%	0.58%
12/31/1981	16.15%	13.68%	2.47%
1/4/1982	15.50%	13.68%	1.82%
1/11/1982	14.50%	13.73%	0.77%
1/11/1982	17.00%	13.73%	3.27%
1/13/1982	14.75%	13.74%	1.01%
1/14/1982	15.75%	13.75%	2.00%
1/15/1982	15.00%	13.76%	1.24%
1/15/1982	16.50%	13.76%	2.74%
1/22/1982	16.25%	13.80%	2.45%
1/27/1982	16.84%	13.81%	3.03%
1/28/1982	13.00%	13.82%	-0.82%
1/29/1982	15.50%	13.82%	1.68%
2/1/1982	15.85%	13.83%	2.02%
2/3/1982	16.44%	13.84%	2.60%
2/8/1982	15.50%	13.86%	1.64%
2/11/1982	16.00%	13.88%	2.12%
2/11/1982	16.20%	13.88%	2.32%
2/17/1982	15.00%	13.89%	1.11%
2/19/1982	15.17%	13.89%	1.28%
2/26/1982	15.25%	13.89%	1.36%
3/1/1982	15.03%	13.89%	1.14%
3/1/1982	16.00%	13.89%	2.11%
3/3/1982	15.00%	13.88%	1.12%
3/8/1982	17.10%	13.88%	3.22%
3/12/1982	16.25%	13.88%	2.37%
3/17/1982	17.30%	13.88%	3.42%
3/22/1982	15.10%	13.89%	1.21%
3/27/1982	15.40%	13.90%	1.50%
3/30/1982	15.50%	13.91%	1.59%
3/31/1982	17.00%	13.91%	3.09%
4/1/1982	16.50%	13.92%	2.58%
4/1/1982	14.70%	13.92%	0.78%
4/2/1982	15.50%	13.92%	1.58%
4/5/1982	15.50%	13.93%	1.57%
4/8/1982	16.40%	13.94%	2.46%
4/13/1982	14.50%	13.94%	0.56%
4/23/1982	15.75%	13.94%	1.81%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
4/27/1982	15.00%	13.94%	1.06%
4/28/1982	15.75%	13.94%	1.81%
4/30/1982	15.50%	13.94%	1.56%
4/30/1982	14.70%	13.94%	0.76%
5/3/1982	16.60%	13.94%	2.66%
5/4/1982	16.00%	13.94%	2.06%
5/14/1982	15.50%	13.92%	1.58%
5/18/1982	15.42%	13.92%	1.50%
5/19/1982	14.69%	13.92%	0.77%
5/20/1982	15.10%	13.91%	1.19%
5/20/1982	15.50%	13.91%	1.59%
5/20/1982	16.30%	13.91%	2.39%
5/20/1982	15.00%	13.91%	1.09%
5/21/1982	17.75%	13.91%	3.84%
5/27/1982	15.00%	13.89%	1.11%
5/28/1982	15.50%	13.89%	1.61%
5/28/1982	17.00%	13.89%	3.11%
6/1/1982	13.75%	13.89%	-0.14%
6/1/1982	16.60%	13.89%	2.71%
6/9/1982	17.86%	13.88%	3.98%
6/14/1982	15.75%	13.88%	1.87%
6/15/1982	14.85%	13.87%	0.98%
6/18/1982	15.50%	13.86%	1.64%
6/21/1982	14.90%	13.86%	1.04%
6/23/1982	16.00%	13.86%	2.14%
6/23/1982	16.17%	13.86%	2.31%
6/24/1982	14.85%	13.86%	0.99%
6/25/1982	14.70%	13.85%	0.85%
7/1/1982	16.00%	13.84%	2.16%
7/2/1982	15.62%	13.83%	1.79%
7/2/1982	17.00%	13.83%	3.17%
7/13/1982	14.00%	13.82%	0.18%
7/13/1982	16.80%	13.82%	2.98%
7/14/1982	15.76%	13.81%	1.95%
7/14/1982	16.02%	13.81%	2.21%
7/19/1982	16.50%	13.79%	2.71%
7/22/1982	17.00%	13.76%	3.24%
7/22/1982	14.50%	13.76%	0.74%
7/27/1982	16.75%	13.74%	3.01%
7/29/1982	16.50%	13.73%	2.77%
8/11/1982	17.50%	13.68%	3.82%
8/18/1982	17.07%	13.62%	3.45%
8/20/1982	15.73%	13.60%	2.13%
8/25/1982	16.00%	13.57%	2.43%
8/26/1982	15.50%	13.56%	1.94%
8/30/1982	15.00%	13.55%	1.45%
9/3/1982	16.20%	13.53%	2.67%
9/8/1982	15.00%	13.52%	1.48%
9/15/1982	13.08%	13.51%	-0.43%
9/15/1982	16.25%	13.51%	2.74%
9/16/1982	16.00%	13.50%	2.50%
9/17/1982	15.25%	13.50%	1.75%
9/23/1982	17.17%	13.47%	3.70%
9/24/1982	14.50%	13.47%	1.03%
9/27/1982	15.25%	13.46%	1.79%
10/1/1982	15.50%	13.42%	2.08%
10/15/1982	15.90%	13.32%	2.58%
10/22/1982	15.75%	13.24%	2.51%
10/22/1982	17.15%	13.24%	3.91%
10/29/1982	15.54%	13.16%	2.38%
11/1/1982	15.50%	13.14%	2.36%
11/3/1982	17.20%	13.12%	4.08%
11/4/1982	16.25%	13.10%	3.15%
11/5/1982	16.20%	13.09%	3.11%
11/9/1982	16.00%	13.05%	2.95%
11/23/1982	15.85%	12.88%	2.97%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
11/23/1982	15.50%	12.88%	2.62%
11/30/1982	16.50%	12.80%	3.70%
12/1/1982	17.04%	12.78%	4.26%
12/6/1982	15.00%	12.72%	2.28%
12/6/1982	16.35%	12.72%	3.63%
12/10/1982	15.50%	12.66%	2.84%
12/13/1982	16.00%	12.64%	3.36%
12/14/1982	16.40%	12.62%	3.78%
12/14/1982	15.30%	12.62%	2.68%
12/20/1982	16.00%	12.57%	3.43%
12/21/1982	15.85%	12.55%	3.30%
12/21/1982	14.75%	12.55%	2.20%
12/22/1982	16.75%	12.54%	4.21%
12/22/1982	16.58%	12.54%	4.04%
12/22/1982	16.25%	12.54%	3.71%
12/29/1982	14.90%	12.48%	2.42%
12/29/1982	16.25%	12.48%	3.77%
12/30/1982	16.35%	12.46%	3.89%
12/30/1982	16.00%	12.46%	3.54%
12/30/1982	16.77%	12.46%	4.31%
1/5/1983	17.33%	12.40%	4.93%
1/11/1983	15.90%	12.34%	3.56%
1/12/1983	15.50%	12.32%	3.18%
1/12/1983	14.63%	12.32%	2.31%
1/20/1983	17.75%	12.23%	5.52%
1/21/1983	15.00%	12.21%	2.79%
1/24/1983	14.50%	12.20%	2.30%
1/24/1983	15.50%	12.20%	3.30%
1/25/1983	15.85%	12.19%	3.66%
1/27/1983	16.14%	12.16%	3.98%
2/1/1983	18.50%	12.13%	6.37%
2/4/1983	14.00%	12.09%	1.91%
2/10/1983	15.00%	12.05%	2.95%
2/21/1983	15.50%	11.98%	3.52%
2/22/1983	15.50%	11.96%	3.54%
2/23/1983	15.10%	11.95%	3.15%
2/23/1983	16.00%	11.95%	4.05%
3/2/1983	15.25%	11.89%	3.36%
3/9/1983	15.20%	11.82%	3.38%
3/15/1983	13.00%	11.76%	1.24%
3/18/1983	15.25%	11.72%	3.53%
3/23/1983	15.40%	11.68%	3.72%
3/24/1983	15.00%	11.66%	3.34%
3/29/1983	15.50%	11.62%	3.88%
3/30/1983	16.71%	11.60%	5.11%
3/31/1983	15.00%	11.58%	3.42%
4/4/1983	15.20%	11.57%	3.63%
4/8/1983	15.50%	11.49%	4.01%
4/11/1983	14.81%	11.48%	3.33%
4/19/1983	14.50%	11.36%	3.14%
4/20/1983	16.00%	11.35%	4.65%
4/29/1983	16.00%	11.23%	4.77%
5/1/1983	14.50%	11.23%	3.27%
5/9/1983	15.50%	11.14%	4.36%
5/11/1983	16.46%	11.11%	5.35%
5/12/1983	14.14%	11.10%	3.04%
5/18/1983	15.00%	11.04%	3.96%
5/23/1983	14.90%	11.00%	3.90%
5/23/1983	15.50%	11.00%	4.50%
5/25/1983	15.50%	10.97%	4.53%
5/27/1983	15.00%	10.95%	4.05%
5/31/1983	15.50%	10.94%	4.56%
5/31/1983	14.00%	10.94%	3.06%
6/2/1983	14.50%	10.92%	3.58%
6/17/1983	15.03%	10.83%	4.20%
7/1/1983	14.80%	10.77%	4.03%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
7/1/1983	14.90%	10.77%	4.13%
7/8/1983	16.25%	10.75%	5.50%
7/13/1983	13.20%	10.75%	2.45%
7/19/1983	15.10%	10.74%	4.36%
7/19/1983	15.00%	10.74%	4.26%
7/25/1983	16.25%	10.73%	5.52%
7/28/1983	15.90%	10.74%	5.16%
8/3/1983	16.50%	10.75%	5.75%
8/3/1983	16.34%	10.75%	5.59%
8/19/1983	15.00%	10.80%	4.20%
8/22/1983	16.40%	10.80%	5.60%
8/22/1983	15.50%	10.80%	4.70%
8/31/1983	14.75%	10.85%	3.90%
9/7/1983	15.00%	10.87%	4.13%
9/14/1983	15.78%	10.89%	4.89%
9/16/1983	15.00%	10.90%	4.10%
9/19/1983	14.50%	10.91%	3.59%
9/20/1983	16.50%	10.91%	5.59%
9/28/1983	14.50%	10.94%	3.56%
9/29/1983	15.50%	10.95%	4.55%
9/30/1983	16.15%	10.95%	5.20%
9/30/1983	15.25%	10.95%	4.30%
10/4/1983	14.80%	10.96%	3.84%
10/7/1983	16.00%	10.97%	5.03%
10/13/1983	15.52%	10.99%	4.53%
10/17/1983	15.50%	11.00%	4.50%
10/18/1983	14.50%	11.00%	3.50%
10/19/1983	16.50%	11.01%	5.49%
10/19/1983	16.25%	11.01%	5.24%
10/26/1983	15.00%	11.04%	3.96%
10/27/1983	15.20%	11.04%	4.16%
11/1/1983	16.00%	11.06%	4.94%
11/9/1983	14.90%	11.09%	3.81%
11/10/1983	14.35%	11.10%	3.25%
11/23/1983	16.00%	11.13%	4.87%
11/23/1983	16.15%	11.13%	5.02%
11/30/1983	15.00%	11.14%	3.86%
12/5/1983	15.25%	11.15%	4.10%
12/6/1983	15.07%	11.16%	3.91%
12/8/1983	15.90%	11.16%	4.74%
12/9/1983	14.75%	11.17%	3.58%
12/12/1983	14.50%	11.18%	3.32%
12/15/1983	15.56%	11.20%	4.36%
12/19/1983	14.80%	11.21%	3.59%
12/20/1983	16.00%	11.22%	4.78%
12/20/1983	14.69%	11.22%	3.47%
12/20/1983	16.25%	11.22%	5.03%
12/22/1983	15.75%	11.23%	4.52%
12/22/1983	14.75%	11.23%	3.52%
1/3/1984	14.75%	11.27%	3.48%
1/10/1984	15.90%	11.30%	4.60%
1/12/1984	15.60%	11.31%	4.29%
1/18/1984	13.75%	11.33%	2.42%
1/19/1984	15.90%	11.33%	4.57%
1/30/1984	16.10%	11.37%	4.73%
1/31/1984	15.25%	11.38%	3.87%
2/1/1984	14.80%	11.39%	3.41%
2/6/1984	14.75%	11.41%	3.34%
2/6/1984	13.75%	11.41%	2.34%
2/9/1984	15.25%	11.43%	3.82%
2/15/1984	15.70%	11.45%	4.25%
2/20/1984	15.00%	11.46%	3.54%
2/20/1984	15.00%	11.46%	3.54%
2/22/1984	14.75%	11.48%	3.27%
2/28/1984	14.50%	11.52%	2.98%
3/2/1984	14.25%	11.54%	2.71%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
3/20/1984	16.00%	11.65%	4.35%
3/23/1984	15.50%	11.67%	3.83%
3/26/1984	14.71%	11.68%	3.03%
4/2/1984	15.50%	11.72%	3.78%
4/6/1984	14.74%	11.76%	2.98%
4/11/1984	15.72%	11.78%	3.94%
4/17/1984	15.00%	11.81%	3.19%
4/18/1984	16.20%	11.82%	4.38%
4/25/1984	14.64%	11.85%	2.79%
4/30/1984	14.40%	11.88%	2.52%
5/16/1984	14.69%	11.99%	2.70%
5/16/1984	15.00%	11.99%	3.01%
5/22/1984	14.40%	12.02%	2.38%
5/29/1984	15.10%	12.06%	3.04%
6/13/1984	15.25%	12.16%	3.09%
6/15/1984	15.60%	12.17%	3.43%
6/22/1984	16.25%	12.21%	4.04%
6/29/1984	15.25%	12.26%	2.99%
7/2/1984	13.35%	12.27%	1.08%
7/10/1984	16.00%	12.31%	3.69%
7/12/1984	16.50%	12.33%	4.17%
7/13/1984	16.25%	12.34%	3.91%
7/17/1984	14.14%	12.35%	1.79%
7/18/1984	15.50%	12.36%	3.14%
7/18/1984	15.30%	12.36%	2.94%
7/19/1984	14.30%	12.37%	1.93%
7/24/1984	16.79%	12.40%	4.39%
7/31/1984	16.00%	12.43%	3.57%
8/3/1984	14.25%	12.45%	1.80%
8/17/1984	14.30%	12.49%	1.81%
8/20/1984	15.00%	12.49%	2.51%
8/27/1984	16.30%	12.51%	3.79%
8/31/1984	15.55%	12.53%	3.02%
9/6/1984	16.00%	12.54%	3.46%
9/10/1984	14.75%	12.55%	2.20%
9/13/1984	15.00%	12.55%	2.45%
9/17/1984	17.38%	12.56%	4.82%
9/26/1984	14.50%	12.57%	1.93%
9/28/1984	16.25%	12.57%	3.68%
9/28/1984	15.00%	12.57%	2.43%
10/9/1984	14.75%	12.58%	2.17%
10/12/1984	15.60%	12.59%	3.01%
10/22/1984	15.00%	12.59%	2.41%
10/26/1984	16.40%	12.59%	3.81%
10/31/1984	16.25%	12.59%	3.66%
11/7/1984	15.60%	12.58%	3.02%
11/9/1984	16.00%	12.58%	3.42%
11/14/1984	15.75%	12.59%	3.16%
11/20/1984	15.25%	12.58%	2.67%
11/20/1984	15.92%	12.58%	3.34%
11/23/1984	15.00%	12.58%	2.42%
11/28/1984	16.15%	12.57%	3.58%
12/3/1984	15.80%	12.57%	3.23%
12/4/1984	16.50%	12.56%	3.94%
12/18/1984	16.40%	12.54%	3.86%
12/19/1984	14.75%	12.53%	2.22%
12/19/1984	15.00%	12.53%	2.47%
12/20/1984	16.00%	12.53%	3.47%
12/28/1984	16.00%	12.50%	3.50%
1/3/1985	14.75%	12.49%	2.26%
1/10/1985	15.75%	12.47%	3.28%
1/11/1985	16.30%	12.46%	3.84%
1/23/1985	15.80%	12.43%	3.37%
1/24/1985	15.82%	12.43%	3.39%
1/25/1985	16.75%	12.42%	4.33%
1/30/1985	14.90%	12.40%	2.50%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/31/1985	14.75%	12.39%	2.36%
2/8/1985	14.47%	12.35%	2.12%
3/1/1985	13.84%	12.30%	1.54%
3/8/1985	16.85%	12.28%	4.57%
3/14/1985	15.50%	12.25%	3.25%
3/15/1985	15.62%	12.25%	3.37%
3/29/1985	15.62%	12.16%	3.46%
4/3/1985	14.60%	12.13%	2.47%
4/9/1985	15.50%	12.10%	3.40%
4/16/1985	15.70%	12.05%	3.65%
4/22/1985	14.00%	12.01%	1.99%
4/26/1985	15.50%	11.97%	3.53%
4/29/1985	15.00%	11.96%	3.04%
5/2/1985	14.68%	11.93%	2.75%
5/8/1985	15.62%	11.88%	3.74%
5/10/1985	16.50%	11.86%	4.64%
5/29/1985	14.61%	11.73%	2.88%
5/31/1985	16.00%	11.71%	4.29%
6/14/1985	15.50%	11.60%	3.90%
7/9/1985	15.00%	11.44%	3.56%
7/16/1985	14.50%	11.39%	3.11%
7/26/1985	14.50%	11.32%	3.18%
8/2/1985	14.80%	11.29%	3.51%
8/7/1985	15.00%	11.26%	3.74%
8/28/1985	14.25%	11.15%	3.10%
8/28/1985	15.50%	11.15%	4.35%
8/29/1985	14.50%	11.14%	3.36%
9/9/1985	14.90%	11.11%	3.79%
9/9/1985	14.60%	11.11%	3.49%
9/17/1985	14.90%	11.08%	3.82%
9/23/1985	15.00%	11.06%	3.94%
9/27/1985	15.50%	11.04%	4.46%
9/27/1985	15.80%	11.04%	4.76%
10/2/1985	14.75%	11.03%	3.72%
10/2/1985	14.00%	11.03%	2.97%
10/3/1985	15.25%	11.03%	4.22%
10/24/1985	15.40%	10.96%	4.44%
10/24/1985	15.85%	10.96%	4.89%
10/24/1985	15.82%	10.96%	4.86%
10/28/1985	16.00%	10.95%	5.05%
10/29/1985	16.65%	10.94%	5.71%
10/31/1985	15.06%	10.93%	4.13%
11/4/1985	14.50%	10.91%	3.59%
11/7/1985	15.50%	10.89%	4.61%
11/8/1985	14.30%	10.89%	3.41%
12/12/1985	14.75%	10.73%	4.02%
12/18/1985	15.00%	10.69%	4.31%
12/20/1985	15.00%	10.66%	4.34%
12/20/1985	14.50%	10.66%	3.84%
12/20/1985	14.50%	10.66%	3.84%
1/24/1986	15.40%	10.40%	5.00%
1/31/1986	15.00%	10.35%	4.65%
2/5/1986	15.00%	10.32%	4.68%
2/5/1986	15.75%	10.32%	5.43%
2/10/1986	13.30%	10.29%	3.01%
2/11/1986	12.50%	10.27%	2.23%
2/14/1986	14.40%	10.24%	4.16%
2/18/1986	16.00%	10.22%	5.78%
2/24/1986	14.50%	10.17%	4.33%
2/26/1986	14.00%	10.15%	3.85%
3/5/1986	14.90%	10.07%	4.83%
3/11/1986	14.50%	10.01%	4.49%
3/12/1986	13.50%	10.00%	3.50%
3/27/1986	14.10%	9.85%	4.25%
3/31/1986	13.50%	9.84%	3.66%
4/1/1986	14.00%	9.82%	4.18%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
4/2/1986	15.50%	9.81%	5.69%
4/4/1986	15.00%	9.78%	5.22%
4/14/1986	13.40%	9.68%	3.72%
4/23/1986	15.00%	9.57%	5.43%
5/16/1986	14.50%	9.31%	5.19%
5/16/1986	14.50%	9.31%	5.19%
5/29/1986	13.90%	9.19%	4.71%
5/30/1986	15.10%	9.17%	5.93%
6/2/1986	12.81%	9.16%	3.65%
6/11/1986	14.00%	9.06%	4.94%
6/24/1986	16.63%	8.93%	7.70%
6/26/1986	12.00%	8.90%	3.10%
6/26/1986	14.75%	8.90%	5.85%
6/30/1986	13.00%	8.86%	4.14%
7/10/1986	14.34%	8.74%	5.60%
7/11/1986	12.75%	8.72%	4.03%
7/14/1986	12.60%	8.71%	3.89%
7/17/1986	12.40%	8.65%	3.75%
7/25/1986	14.25%	8.56%	5.69%
8/6/1986	13.50%	8.43%	5.07%
8/14/1986	13.50%	8.34%	5.16%
9/16/1986	12.75%	8.06%	4.69%
9/19/1986	13.25%	8.02%	5.23%
10/1/1986	14.00%	7.94%	6.06%
10/3/1986	13.40%	7.92%	5.48%
10/31/1986	13.50%	7.77%	5.73%
11/5/1986	13.00%	7.74%	5.26%
12/3/1986	12.90%	7.58%	5.32%
12/4/1986	14.44%	7.57%	6.87%
12/16/1986	13.60%	7.52%	6.08%
12/22/1986	13.80%	7.50%	6.30%
12/30/1986	13.00%	7.49%	5.51%
1/2/1987	13.00%	7.48%	5.52%
1/12/1987	12.40%	7.46%	4.94%
1/27/1987	12.71%	7.46%	5.25%
3/2/1987	12.47%	7.47%	5.00%
3/3/1987	13.60%	7.47%	6.13%
3/4/1987	12.38%	7.47%	4.91%
3/10/1987	13.50%	7.47%	6.03%
3/13/1987	13.00%	7.47%	5.53%
3/31/1987	13.00%	7.46%	5.54%
4/6/1987	13.00%	7.47%	5.53%
4/14/1987	12.50%	7.49%	5.01%
4/16/1987	14.50%	7.50%	7.00%
4/27/1987	12.00%	7.54%	4.46%
5/5/1987	12.85%	7.58%	5.27%
5/12/1987	12.65%	7.62%	5.03%
5/28/1987	13.50%	7.70%	5.80%
6/15/1987	13.20%	7.78%	5.42%
6/29/1987	15.00%	7.84%	7.16%
6/30/1987	12.50%	7.84%	4.66%
7/8/1987	12.00%	7.86%	4.14%
7/10/1987	12.90%	7.87%	5.03%
7/15/1987	13.50%	7.88%	5.62%
7/16/1987	15.00%	7.88%	7.12%
7/16/1987	13.50%	7.88%	5.62%
7/27/1987	13.00%	7.92%	5.08%
7/27/1987	13.40%	7.92%	5.48%
7/27/1987	13.50%	7.92%	5.58%
7/31/1987	12.98%	7.95%	5.03%
8/26/1987	12.63%	8.06%	4.57%
8/26/1987	12.75%	8.06%	4.69%
8/27/1987	13.25%	8.07%	5.18%
9/9/1987	13.00%	8.14%	4.86%
9/30/1987	13.00%	8.31%	4.69%
9/30/1987	12.75%	8.31%	4.44%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/2/1987	11.50%	8.33%	3.17%
10/15/1987	13.00%	8.44%	4.56%
11/2/1987	13.00%	8.55%	4.45%
11/19/1987	13.00%	8.64%	4.36%
11/30/1987	12.00%	8.69%	3.31%
12/3/1987	14.20%	8.71%	5.49%
12/15/1987	13.25%	8.78%	4.47%
12/16/1987	13.72%	8.79%	4.93%
12/16/1987	13.50%	8.79%	4.71%
12/17/1987	11.75%	8.80%	2.95%
12/18/1987	13.50%	8.80%	4.70%
12/21/1987	12.01%	8.81%	3.20%
12/22/1987	12.75%	8.82%	3.93%
12/22/1987	12.00%	8.82%	3.18%
12/22/1987	12.00%	8.82%	3.18%
12/22/1987	13.00%	8.82%	4.18%
1/20/1988	13.80%	8.94%	4.86%
1/26/1988	13.90%	8.96%	4.94%
1/29/1988	13.20%	8.96%	4.24%
2/4/1988	12.60%	8.96%	3.64%
3/1/1988	11.56%	8.94%	2.62%
3/23/1988	12.87%	8.92%	3.95%
3/24/1988	11.24%	8.92%	2.32%
3/30/1988	12.72%	8.92%	3.80%
4/1/1988	12.50%	8.92%	3.58%
4/7/1988	13.25%	8.93%	4.32%
4/25/1988	10.96%	8.96%	2.00%
5/3/1988	12.91%	8.98%	3.93%
5/11/1988	13.50%	8.99%	4.51%
5/16/1988	13.00%	8.99%	4.01%
6/30/1988	12.75%	8.99%	3.76%
7/1/1988	12.75%	8.99%	3.76%
7/20/1988	13.40%	8.96%	4.44%
8/5/1988	12.75%	8.91%	3.84%
8/23/1988	11.70%	8.93%	2.77%
8/29/1988	12.75%	8.94%	3.81%
8/30/1988	13.50%	8.94%	4.56%
9/8/1988	12.60%	8.95%	3.65%
10/13/1988	13.10%	8.93%	4.17%
12/19/1988	13.00%	9.02%	3.98%
12/20/1988	13.00%	9.02%	3.98%
12/20/1988	12.25%	9.02%	3.23%
12/21/1988	12.90%	9.02%	3.88%
12/27/1988	13.00%	9.03%	3.97%
12/28/1988	13.10%	9.03%	4.07%
12/30/1988	13.40%	9.04%	4.36%
1/27/1989	13.00%	9.06%	3.94%
1/31/1989	13.00%	9.06%	3.94%
2/17/1989	13.00%	9.05%	3.95%
2/20/1989	12.40%	9.05%	3.35%
3/1/1989	12.76%	9.05%	3.71%
3/8/1989	13.00%	9.05%	3.95%
3/30/1989	14.00%	9.05%	4.95%
4/5/1989	14.20%	9.05%	5.15%
4/18/1989	13.00%	9.05%	3.95%
5/5/1989	12.40%	9.05%	3.35%
6/2/1989	13.20%	9.00%	4.20%
6/8/1989	13.50%	8.98%	4.52%
6/27/1989	13.25%	8.91%	4.34%
6/30/1989	13.00%	8.90%	4.10%
8/14/1989	12.50%	8.77%	3.73%
9/28/1989	12.25%	8.63%	3.62%
10/24/1989	12.50%	8.54%	3.96%
11/9/1989	13.00%	8.48%	4.52%
12/15/1989	13.00%	8.33%	4.67%
12/20/1989	12.90%	8.31%	4.59%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/21/1989	12.90%	8.31%	4.59%
12/27/1989	13.00%	8.29%	4.71%
12/27/1989	12.50%	8.29%	4.21%
1/10/1990	12.80%	8.24%	4.56%
1/11/1990	12.90%	8.23%	4.67%
1/17/1990	12.80%	8.22%	4.58%
1/26/1990	12.00%	8.19%	3.81%
2/9/1990	12.10%	8.17%	3.93%
2/24/1990	12.86%	8.15%	4.71%
3/30/1990	12.90%	8.16%	4.74%
4/4/1990	15.76%	8.17%	7.59%
4/12/1990	12.52%	8.18%	4.34%
4/19/1990	12.75%	8.20%	4.55%
5/21/1990	12.10%	8.28%	3.82%
5/29/1990	12.40%	8.30%	4.10%
5/31/1990	12.00%	8.30%	3.70%
6/4/1990	12.90%	8.30%	4.60%
6/6/1990	12.25%	8.31%	3.94%
6/15/1990	13.20%	8.32%	4.88%
6/20/1990	12.92%	8.32%	4.60%
6/27/1990	12.90%	8.33%	4.57%
6/29/1990	12.50%	8.34%	4.16%
7/6/1990	12.35%	8.34%	4.01%
7/6/1990	12.10%	8.34%	3.76%
8/10/1990	12.55%	8.41%	4.14%
8/16/1990	13.21%	8.43%	4.78%
8/22/1990	13.10%	8.45%	4.65%
8/24/1990	13.00%	8.46%	4.54%
9/26/1990	11.45%	8.59%	2.86%
10/2/1990	13.00%	8.61%	4.39%
10/5/1990	12.84%	8.63%	4.21%
10/19/1990	13.00%	8.67%	4.33%
10/25/1990	12.30%	8.68%	3.62%
11/21/1990	12.70%	8.69%	4.01%
12/13/1990	12.30%	8.67%	3.63%
12/17/1990	12.87%	8.67%	4.20%
12/18/1990	13.10%	8.67%	4.43%
12/19/1990	12.00%	8.66%	3.34%
12/20/1990	12.75%	8.66%	4.09%
12/21/1990	12.50%	8.66%	3.84%
12/27/1990	12.79%	8.66%	4.13%
1/2/1991	13.10%	8.66%	4.44%
1/4/1991	12.50%	8.65%	3.85%
1/15/1991	12.75%	8.65%	4.10%
1/25/1991	11.70%	8.63%	3.07%
2/4/1991	12.50%	8.60%	3.90%
2/7/1991	12.50%	8.59%	3.91%
2/12/1991	13.00%	8.57%	4.43%
2/14/1991	12.72%	8.56%	4.16%
2/22/1991	12.80%	8.55%	4.25%
3/6/1991	13.10%	8.53%	4.57%
3/8/1991	13.00%	8.52%	4.48%
3/8/1991	12.30%	8.52%	3.78%
4/22/1991	13.00%	8.49%	4.51%
5/7/1991	13.50%	8.47%	5.03%
5/13/1991	13.25%	8.47%	4.78%
5/30/1991	12.75%	8.43%	4.32%
6/12/1991	12.00%	8.41%	3.59%
6/25/1991	11.70%	8.38%	3.32%
6/28/1991	12.50%	8.38%	4.12%
7/1/1991	12.00%	8.37%	3.63%
7/3/1991	12.50%	8.36%	4.14%
7/19/1991	12.10%	8.34%	3.76%
8/1/1991	12.90%	8.32%	4.58%
8/16/1991	13.20%	8.29%	4.91%
9/27/1991	12.50%	8.23%	4.27%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
9/30/1991	12.25%	8.23%	4.02%
10/17/1991	13.00%	8.20%	4.80%
10/23/1991	12.50%	8.20%	4.30%
10/23/1991	12.55%	8.20%	4.35%
10/31/1991	11.80%	8.19%	3.61%
11/1/1991	12.00%	8.19%	3.81%
11/5/1991	12.25%	8.19%	4.06%
11/12/1991	12.50%	8.18%	4.32%
11/12/1991	13.25%	8.18%	5.07%
11/25/1991	12.40%	8.18%	4.22%
11/26/1991	12.50%	8.18%	4.32%
11/26/1991	11.60%	8.18%	3.42%
11/27/1991	12.10%	8.18%	3.92%
12/18/1991	12.25%	8.15%	4.10%
12/19/1991	12.60%	8.15%	4.45%
12/19/1991	12.80%	8.15%	4.65%
12/20/1991	12.65%	8.14%	4.51%
1/9/1992	12.80%	8.09%	4.71%
1/16/1992	12.75%	8.07%	4.68%
1/21/1992	12.00%	8.06%	3.94%
1/22/1992	13.00%	8.06%	4.94%
1/27/1992	12.65%	8.05%	4.60%
1/31/1992	12.00%	8.04%	3.96%
2/11/1992	12.40%	8.03%	4.37%
2/25/1992	12.50%	8.01%	4.49%
3/16/1992	11.43%	7.98%	3.45%
3/18/1992	12.28%	7.98%	4.30%
4/2/1992	12.10%	7.95%	4.15%
4/9/1992	11.45%	7.93%	3.52%
4/10/1992	11.50%	7.93%	3.57%
4/14/1992	11.50%	7.92%	3.58%
5/5/1992	11.50%	7.89%	3.61%
5/12/1992	12.46%	7.88%	4.58%
5/12/1992	11.87%	7.88%	3.99%
6/1/1992	12.30%	7.86%	4.44%
6/12/1992	10.90%	7.85%	3.05%
6/26/1992	12.35%	7.85%	4.50%
6/29/1992	11.00%	7.85%	3.15%
6/30/1992	13.00%	7.85%	5.15%
7/13/1992	13.50%	7.84%	5.66%
7/13/1992	11.90%	7.84%	4.06%
7/22/1992	11.20%	7.83%	3.37%
8/3/1992	12.00%	7.81%	4.19%
8/6/1992	12.50%	7.80%	4.70%
9/22/1992	12.00%	7.71%	4.29%
9/28/1992	11.40%	7.71%	3.69%
9/30/1992	11.75%	7.71%	4.04%
10/2/1992	13.00%	7.70%	5.30%
10/12/1992	12.20%	7.70%	4.50%
10/16/1992	13.16%	7.71%	5.45%
10/30/1992	11.75%	7.71%	4.04%
11/3/1992	12.00%	7.71%	4.29%
12/3/1992	11.85%	7.68%	4.17%
12/15/1992	11.00%	7.66%	3.34%
12/16/1992	11.90%	7.66%	4.24%
12/16/1992	12.40%	7.66%	4.74%
12/17/1992	12.00%	7.66%	4.34%
12/22/1992	12.40%	7.65%	4.75%
12/22/1992	12.30%	7.65%	4.65%
12/29/1992	12.25%	7.63%	4.62%
12/30/1992	12.00%	7.63%	4.37%
12/31/1992	11.90%	7.62%	4.28%
1/12/1993	12.00%	7.61%	4.39%
1/21/1993	11.25%	7.59%	3.66%
2/2/1993	11.40%	7.56%	3.84%
2/15/1993	12.30%	7.52%	4.78%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
2/24/1993	11.90%	7.49%	4.41%
2/26/1993	11.80%	7.48%	4.32%
2/26/1993	12.20%	7.48%	4.72%
4/23/1993	11.75%	7.29%	4.46%
5/11/1993	11.75%	7.24%	4.51%
5/14/1993	11.50%	7.24%	4.26%
5/25/1993	11.50%	7.22%	4.28%
5/28/1993	11.00%	7.22%	3.78%
6/3/1993	12.00%	7.21%	4.79%
6/16/1993	11.50%	7.19%	4.31%
6/18/1993	12.10%	7.18%	4.92%
6/25/1993	11.67%	7.17%	4.50%
7/21/1993	11.38%	7.10%	4.28%
7/23/1993	10.46%	7.09%	3.37%
8/24/1993	11.50%	6.95%	4.55%
9/21/1993	10.50%	6.80%	3.70%
9/29/1993	11.47%	6.76%	4.71%
9/30/1993	11.60%	6.76%	4.84%
11/2/1993	10.80%	6.60%	4.20%
11/12/1993	12.00%	6.56%	5.44%
11/26/1993	11.00%	6.52%	4.48%
12/14/1993	10.55%	6.48%	4.07%
12/16/1993	10.60%	6.48%	4.12%
12/21/1993	11.30%	6.47%	4.83%
1/4/1994	10.07%	6.44%	3.63%
1/13/1994	11.00%	6.42%	4.58%
1/21/1994	11.00%	6.40%	4.60%
1/28/1994	11.35%	6.39%	4.96%
2/3/1994	11.40%	6.38%	5.02%
2/17/1994	10.60%	6.36%	4.24%
2/25/1994	11.25%	6.35%	4.90%
2/25/1994	12.00%	6.35%	5.65%
3/1/1994	11.00%	6.35%	4.65%
3/4/1994	11.00%	6.34%	4.66%
4/25/1994	11.00%	6.40%	4.60%
5/10/1994	11.75%	6.44%	5.31%
5/13/1994	10.50%	6.46%	4.04%
6/3/1994	11.00%	6.54%	4.46%
6/27/1994	11.40%	6.65%	4.75%
8/5/1994	12.75%	6.88%	5.87%
10/31/1994	10.00%	7.33%	2.67%
11/9/1994	10.85%	7.40%	3.45%
11/9/1994	10.85%	7.40%	3.45%
11/18/1994	11.20%	7.46%	3.74%
11/22/1994	11.60%	7.47%	4.13%
11/28/1994	11.06%	7.50%	3.56%
12/8/1994	11.70%	7.55%	4.15%
12/8/1994	11.50%	7.55%	3.95%
12/14/1994	10.95%	7.57%	3.38%
12/15/1994	11.50%	7.57%	3.93%
12/19/1994	11.50%	7.58%	3.92%
12/28/1994	12.15%	7.61%	4.54%
1/9/1995	12.28%	7.64%	4.64%
1/31/1995	11.00%	7.69%	3.31%
2/10/1995	12.60%	7.70%	4.90%
2/17/1995	11.90%	7.70%	4.20%
3/9/1995	11.50%	7.72%	3.78%
3/20/1995	12.00%	7.72%	4.28%
3/23/1995	12.81%	7.72%	5.09%
3/29/1995	11.60%	7.72%	3.88%
4/6/1995	11.10%	7.72%	3.38%
4/7/1995	11.00%	7.71%	3.29%
4/19/1995	11.00%	7.70%	3.30%
5/12/1995	11.63%	7.68%	3.95%
5/25/1995	11.20%	7.65%	3.55%
6/9/1995	11.25%	7.60%	3.65%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
6/21/1995	12.25%	7.56%	4.69%
6/30/1995	11.10%	7.51%	3.59%
9/11/1995	11.30%	7.20%	4.10%
9/27/1995	11.50%	7.12%	4.38%
9/27/1995	11.75%	7.12%	4.63%
9/27/1995	11.30%	7.12%	4.18%
9/29/1995	11.00%	7.11%	3.89%
11/9/1995	12.36%	6.89%	5.47%
11/9/1995	11.38%	6.89%	4.49%
11/17/1995	11.00%	6.85%	4.15%
12/4/1995	11.35%	6.78%	4.57%
12/11/1995	11.40%	6.74%	4.66%
12/20/1995	11.60%	6.69%	4.91%
12/27/1995	12.00%	6.66%	5.34%
2/5/1996	12.25%	6.48%	5.77%
3/29/1996	10.67%	6.42%	4.25%
4/8/1996	11.00%	6.42%	4.58%
4/11/1996	12.59%	6.43%	6.16%
4/11/1996	12.59%	6.43%	6.16%
4/24/1996	11.25%	6.43%	4.82%
4/30/1996	11.00%	6.43%	4.57%
5/13/1996	11.00%	6.44%	4.56%
5/23/1996	11.25%	6.43%	4.82%
6/25/1996	11.25%	6.48%	4.77%
6/27/1996	11.20%	6.48%	4.72%
8/12/1996	10.40%	6.57%	3.83%
9/27/1996	11.00%	6.71%	4.29%
10/16/1996	12.25%	6.76%	5.49%
11/5/1996	11.00%	6.81%	4.19%
11/26/1996	11.30%	6.83%	4.47%
12/18/1996	11.75%	6.84%	4.91%
12/31/1996	11.50%	6.83%	4.67%
1/3/1997	10.70%	6.83%	3.87%
2/13/1997	11.80%	6.82%	4.98%
2/20/1997	11.80%	6.82%	4.98%
3/31/1997	10.02%	6.80%	3.22%
4/2/1997	11.65%	6.80%	4.85%
4/28/1997	11.50%	6.81%	4.69%
4/29/1997	11.70%	6.81%	4.89%
7/17/1997	12.00%	6.77%	5.23%
12/12/1997	11.00%	6.60%	4.40%
12/23/1997	11.12%	6.57%	4.55%
2/2/1998	12.75%	6.39%	6.36%
3/2/1998	11.25%	6.28%	4.97%
3/6/1998	10.75%	6.27%	4.48%
3/20/1998	10.50%	6.22%	4.28%
4/30/1998	12.20%	6.12%	6.08%
7/10/1998	11.40%	5.94%	5.46%
9/15/1998	11.90%	5.78%	6.12%
11/30/1998	12.60%	5.58%	7.02%
12/10/1998	12.20%	5.54%	6.66%
12/17/1998	12.10%	5.52%	6.58%
2/5/1999	10.30%	5.38%	4.92%
3/4/1999	10.50%	5.34%	5.16%
4/6/1999	10.94%	5.32%	5.62%
7/29/1999	10.75%	5.52%	5.23%
9/23/1999	10.75%	5.70%	5.05%
11/17/1999	11.10%	5.90%	5.20%
1/7/2000	11.50%	6.05%	5.45%
1/7/2000	11.50%	6.05%	5.45%
2/17/2000	10.60%	6.17%	4.43%
3/28/2000	11.25%	6.20%	5.05%
5/24/2000	11.00%	6.18%	4.82%
7/18/2000	12.20%	6.16%	6.04%
9/29/2000	11.16%	6.03%	5.13%
11/28/2000	12.90%	5.89%	7.01%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
11/30/2000	12.10%	5.88%	6.22%
1/23/2001	11.25%	5.79%	5.46%
2/8/2001	11.50%	5.77%	5.73%
5/8/2001	10.75%	5.62%	5.13%
6/26/2001	11.00%	5.62%	5.38%
7/25/2001	11.02%	5.60%	5.42%
7/25/2001	11.02%	5.60%	5.42%
7/31/2001	11.00%	5.59%	5.41%
8/31/2001	10.50%	5.56%	4.94%
9/7/2001	10.75%	5.55%	5.20%
9/10/2001	11.00%	5.55%	5.45%
9/20/2001	10.00%	5.55%	4.45%
10/24/2001	10.30%	5.54%	4.76%
11/28/2001	10.60%	5.49%	5.11%
12/3/2001	12.88%	5.49%	7.39%
12/20/2001	12.50%	5.50%	7.00%
1/22/2002	10.00%	5.50%	4.50%
3/27/2002	10.10%	5.45%	4.65%
4/22/2002	11.80%	5.45%	6.35%
5/28/2002	10.17%	5.46%	4.71%
6/10/2002	12.00%	5.47%	6.53%
6/18/2002	11.16%	5.48%	5.68%
6/20/2002	11.00%	5.48%	5.52%
6/20/2002	12.30%	5.48%	6.82%
7/15/2002	11.00%	5.48%	5.52%
9/12/2002	12.30%	5.45%	6.85%
9/26/2002	10.45%	5.41%	5.04%
12/4/2002	11.55%	5.29%	6.26%
12/13/2002	11.75%	5.27%	6.48%
12/20/2002	11.40%	5.25%	6.15%
1/8/2003	11.10%	5.19%	5.91%
1/31/2003	12.45%	5.13%	7.32%
2/28/2003	12.30%	5.04%	7.26%
3/6/2003	10.75%	5.02%	5.73%
3/7/2003	9.96%	5.02%	4.94%
3/20/2003	12.00%	4.98%	7.02%
4/3/2003	12.00%	4.95%	7.05%
4/15/2003	11.15%	4.93%	6.22%
6/25/2003	10.75%	4.79%	5.96%
6/26/2003	10.75%	4.79%	5.96%
7/9/2003	9.75%	4.79%	4.96%
7/16/2003	9.75%	4.79%	4.96%
7/25/2003	9.50%	4.79%	4.71%
8/26/2003	10.50%	4.83%	5.67%
12/17/2003	9.85%	4.94%	4.91%
12/17/2003	10.70%	4.94%	5.76%
12/18/2003	11.50%	4.94%	6.56%
12/19/2003	12.00%	4.94%	7.06%
12/19/2003	12.00%	4.94%	7.06%
12/23/2003	10.50%	4.94%	5.56%
1/13/2004	12.00%	4.95%	7.05%
3/2/2004	10.75%	4.99%	5.76%
3/26/2004	10.25%	5.02%	5.23%
4/5/2004	11.25%	5.03%	6.22%
5/18/2004	10.50%	5.07%	5.43%
5/25/2004	10.25%	5.07%	5.18%
5/27/2004	10.25%	5.08%	5.17%
6/2/2004	11.22%	5.08%	6.14%
6/30/2004	10.50%	5.10%	5.40%
6/30/2004	10.50%	5.10%	5.40%
7/16/2004	11.60%	5.11%	6.49%
8/25/2004	10.25%	5.10%	5.15%
9/9/2004	10.40%	5.10%	5.30%
11/9/2004	10.50%	5.07%	5.43%
11/23/2004	11.00%	5.06%	5.94%
12/14/2004	10.97%	5.07%	5.90%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/21/2004	11.25%	5.07%	6.18%
12/21/2004	11.50%	5.07%	6.43%
12/22/2004	10.70%	5.07%	5.63%
12/22/2004	11.50%	5.07%	6.43%
12/29/2004	9.85%	5.08%	4.77%
1/6/2005	10.70%	5.08%	5.62%
2/18/2005	10.30%	4.98%	5.32%
2/25/2005	10.50%	4.96%	5.54%
3/10/2005	11.00%	4.93%	6.07%
3/24/2005	10.30%	4.89%	5.41%
4/4/2005	10.00%	4.87%	5.13%
4/7/2005	10.25%	4.87%	5.38%
5/18/2005	10.25%	4.78%	5.47%
5/25/2005	10.75%	4.76%	5.99%
5/26/2005	9.75%	4.76%	4.99%
6/1/2005	9.75%	4.75%	5.00%
7/19/2005	11.50%	4.64%	6.86%
8/5/2005	11.75%	4.62%	7.13%
8/15/2005	10.13%	4.61%	5.52%
9/28/2005	10.00%	4.54%	5.46%
10/4/2005	10.75%	4.53%	6.22%
12/12/2005	11.00%	4.55%	6.45%
12/13/2005	10.75%	4.55%	6.20%
12/21/2005	10.29%	4.54%	5.75%
12/21/2005	10.40%	4.54%	5.86%
12/22/2005	11.15%	4.54%	6.61%
12/22/2005	11.00%	4.54%	6.46%
12/28/2005	10.00%	4.54%	5.46%
12/28/2005	10.00%	4.54%	5.46%
1/5/2006	11.00%	4.53%	6.47%
1/27/2006	9.75%	4.52%	5.23%
3/3/2006	10.39%	4.53%	5.86%
4/17/2006	10.20%	4.62%	5.58%
4/26/2006	10.60%	4.64%	5.96%
5/17/2006	11.60%	4.69%	6.91%
6/6/2006	10.00%	4.75%	5.25%
6/27/2006	10.75%	4.80%	5.95%
7/6/2006	10.20%	4.83%	5.37%
7/24/2006	9.60%	4.86%	4.74%
7/26/2006	10.50%	4.86%	5.64%
7/28/2006	10.05%	4.87%	5.18%
8/23/2006	9.55%	4.89%	4.66%
9/1/2006	10.54%	4.90%	5.64%
9/14/2006	10.00%	4.91%	5.09%
10/6/2006	9.67%	4.92%	4.75%
11/21/2006	10.08%	4.95%	5.13%
11/21/2006	10.08%	4.95%	5.13%
11/21/2006	10.12%	4.95%	5.17%
12/1/2006	10.50%	4.96%	5.54%
12/1/2006	10.25%	4.96%	5.29%
12/7/2006	10.75%	4.96%	5.79%
12/21/2006	10.90%	4.95%	5.95%
12/21/2006	11.25%	4.95%	6.30%
12/22/2006	10.25%	4.95%	5.30%
1/5/2007	10.00%	4.95%	5.05%
1/11/2007	10.10%	4.95%	5.15%
1/11/2007	10.10%	4.95%	5.15%
1/11/2007	10.90%	4.95%	5.95%
1/12/2007	10.10%	4.95%	5.15%
1/13/2007	10.40%	4.95%	5.45%
1/19/2007	10.80%	4.94%	5.86%
3/21/2007	11.35%	4.86%	6.49%
3/22/2007	9.75%	4.86%	4.89%
5/15/2007	10.00%	4.81%	5.19%
5/17/2007	10.25%	4.80%	5.45%
5/17/2007	10.25%	4.80%	5.45%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
5/22/2007	10.20%	4.80%	5.40%
5/22/2007	10.50%	4.80%	5.70%
5/23/2007	10.70%	4.80%	5.90%
5/25/2007	9.67%	4.80%	4.87%
6/15/2007	9.90%	4.82%	5.08%
6/21/2007	10.20%	4.83%	5.37%
6/22/2007	10.50%	4.83%	5.67%
6/28/2007	10.75%	4.84%	5.91%
7/12/2007	9.67%	4.86%	4.81%
7/19/2007	10.00%	4.87%	5.13%
7/19/2007	10.00%	4.87%	5.13%
8/15/2007	10.40%	4.88%	5.52%
10/9/2007	10.00%	4.91%	5.09%
10/17/2007	9.10%	4.91%	4.19%
10/31/2007	9.96%	4.90%	5.06%
11/29/2007	10.90%	4.87%	6.03%
12/6/2007	10.75%	4.86%	5.89%
12/13/2007	9.96%	4.86%	5.10%
12/14/2007	10.70%	4.86%	5.84%
12/14/2007	10.80%	4.86%	5.94%
12/19/2007	10.20%	4.86%	5.34%
12/20/2007	10.20%	4.86%	5.34%
12/20/2007	11.00%	4.86%	6.14%
12/28/2007	10.25%	4.85%	5.40%
12/31/2007	11.25%	4.85%	6.40%
1/8/2008	10.75%	4.83%	5.92%
1/17/2008	10.75%	4.81%	5.94%
1/28/2008	9.40%	4.80%	4.60%
1/30/2008	10.00%	4.79%	5.21%
1/31/2008	10.71%	4.79%	5.92%
2/29/2008	10.25%	4.75%	5.50%
3/12/2008	10.25%	4.73%	5.52%
3/25/2008	9.10%	4.68%	4.42%
4/22/2008	10.25%	4.60%	5.65%
4/24/2008	10.10%	4.60%	5.50%
5/1/2008	10.70%	4.58%	6.12%
5/19/2008	11.00%	4.56%	6.44%
5/27/2008	10.00%	4.55%	5.45%
6/10/2008	10.70%	4.54%	6.16%
6/27/2008	11.04%	4.54%	6.50%
6/27/2008	10.50%	4.54%	5.96%
7/10/2008	10.43%	4.52%	5.91%
7/16/2008	9.40%	4.51%	4.89%
7/30/2008	10.80%	4.51%	6.29%
7/31/2008	10.70%	4.51%	6.19%
8/11/2008	10.25%	4.50%	5.75%
8/26/2008	10.18%	4.50%	5.68%
9/10/2008	10.30%	4.50%	5.80%
9/24/2008	10.65%	4.48%	6.17%
9/24/2008	10.65%	4.48%	6.17%
9/24/2008	10.65%	4.48%	6.17%
9/30/2008	10.20%	4.47%	5.73%
10/8/2008	10.15%	4.46%	5.69%
11/13/2008	10.55%	4.45%	6.10%
11/17/2008	10.20%	4.44%	5.76%
12/1/2008	10.25%	4.39%	5.86%
12/23/2008	11.00%	4.27%	6.73%
12/29/2008	10.00%	4.24%	5.76%
12/29/2008	10.20%	4.24%	5.96%
12/31/2008	10.75%	4.22%	6.53%
1/14/2009	10.50%	4.15%	6.35%
1/21/2009	10.50%	4.11%	6.39%
1/21/2009	10.50%	4.11%	6.39%
1/21/2009	10.50%	4.11%	6.39%
1/27/2009	10.76%	4.09%	6.67%
1/30/2009	10.50%	4.07%	6.43%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
2/4/2009	8.75%	4.06%	4.69%
3/4/2009	10.50%	3.96%	6.54%
3/12/2009	11.50%	3.93%	7.57%
4/2/2009	11.10%	3.85%	7.25%
4/21/2009	10.61%	3.80%	6.81%
4/24/2009	10.00%	3.78%	6.22%
4/30/2009	11.25%	3.77%	7.48%
5/4/2009	10.74%	3.77%	6.97%
5/20/2009	10.25%	3.74%	6.51%
5/28/2009	10.50%	3.74%	6.76%
6/22/2009	10.00%	3.76%	6.24%
6/24/2009	10.80%	3.76%	7.04%
7/8/2009	10.63%	3.76%	6.87%
7/17/2009	10.50%	3.77%	6.73%
8/21/2009	10.25%	3.80%	6.45%
8/31/2009	10.25%	3.82%	6.43%
10/14/2009	10.70%	4.02%	6.68%
10/23/2009	10.88%	4.06%	6.82%
11/2/2009	10.70%	4.10%	6.60%
11/3/2009	10.70%	4.10%	6.60%
11/24/2009	10.25%	4.16%	6.09%
11/25/2009	10.75%	4.16%	6.59%
11/30/2009	10.35%	4.17%	6.18%
12/3/2009	10.50%	4.18%	6.32%
12/7/2009	10.70%	4.19%	6.51%
12/16/2009	11.00%	4.22%	6.78%
12/16/2009	10.90%	4.22%	6.68%
12/18/2009	10.40%	4.22%	6.18%
12/18/2009	10.40%	4.22%	6.18%
12/22/2009	10.20%	4.23%	5.97%
12/22/2009	10.40%	4.23%	6.17%
12/22/2009	10.40%	4.23%	6.17%
12/30/2009	10.00%	4.26%	5.74%
1/4/2010	10.80%	4.28%	6.52%
1/11/2010	11.00%	4.31%	6.69%
1/26/2010	10.13%	4.35%	5.78%
1/27/2010	10.40%	4.36%	6.04%
1/27/2010	10.40%	4.36%	6.04%
1/27/2010	10.70%	4.36%	6.34%
2/9/2010	9.80%	4.38%	5.42%
2/18/2010	10.60%	4.40%	6.20%
2/24/2010	10.18%	4.41%	5.77%
3/2/2010	9.63%	4.41%	5.22%
3/4/2010	10.50%	4.41%	6.09%
3/5/2010	10.50%	4.41%	6.09%
3/11/2010	11.90%	4.42%	7.48%
3/17/2010	10.00%	4.41%	5.59%
3/25/2010	10.15%	4.42%	5.73%
4/2/2010	10.10%	4.43%	5.67%
4/27/2010	10.00%	4.46%	5.54%
4/29/2010	9.90%	4.46%	5.44%
4/29/2010	10.06%	4.46%	5.60%
4/29/2010	10.26%	4.46%	5.80%
5/12/2010	10.30%	4.45%	5.85%
5/12/2010	10.30%	4.45%	5.85%
5/28/2010	10.20%	4.44%	5.76%
5/28/2010	10.10%	4.44%	5.66%
6/7/2010	10.30%	4.44%	5.86%
6/16/2010	10.00%	4.44%	5.56%
6/28/2010	10.50%	4.43%	6.07%
6/28/2010	9.67%	4.43%	5.24%
6/30/2010	9.40%	4.43%	4.97%
7/1/2010	10.25%	4.43%	5.82%
7/15/2010	10.70%	4.43%	6.27%
7/15/2010	10.53%	4.43%	6.10%
7/30/2010	10.70%	4.41%	6.29%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
8/4/2010	10.50%	4.41%	6.09%
8/6/2010	9.83%	4.41%	5.42%
8/25/2010	9.90%	4.37%	5.53%
9/3/2010	10.60%	4.35%	6.25%
9/14/2010	10.70%	4.33%	6.37%
9/16/2010	10.00%	4.32%	5.68%
9/16/2010	10.00%	4.32%	5.68%
9/30/2010	9.75%	4.28%	5.47%
10/14/2010	10.35%	4.24%	6.11%
10/28/2010	10.70%	4.21%	6.49%
11/2/2010	10.38%	4.20%	6.18%
11/4/2010	10.70%	4.19%	6.51%
11/19/2010	10.20%	4.17%	6.03%
11/22/2010	10.00%	4.17%	5.83%
12/1/2010	10.13%	4.16%	5.97%
12/6/2010	9.86%	4.15%	5.71%
12/9/2010	10.25%	4.15%	6.10%
12/13/2010	10.70%	4.15%	6.55%
12/14/2010	10.13%	4.15%	5.98%
12/15/2010	10.44%	4.15%	6.29%
12/17/2010	10.00%	4.14%	5.86%
12/20/2010	10.60%	4.14%	6.46%
12/21/2010	10.30%	4.14%	6.16%
12/27/2010	9.90%	4.14%	5.76%
12/29/2010	11.15%	4.14%	7.01%
1/5/2011	10.15%	4.13%	6.02%
1/12/2011	10.30%	4.12%	6.18%
1/13/2011	10.30%	4.12%	6.18%
1/18/2011	10.00%	4.12%	5.88%
1/20/2011	9.30%	4.12%	5.18%
1/20/2011	10.13%	4.12%	6.01%
1/31/2011	9.60%	4.11%	5.49%
2/3/2011	10.00%	4.11%	5.89%
2/25/2011	10.00%	4.14%	5.86%
3/25/2011	9.80%	4.18%	5.62%
3/30/2011	10.00%	4.18%	5.82%
4/12/2011	10.00%	4.21%	5.79%
4/25/2011	10.74%	4.23%	6.51%
4/26/2011	9.67%	4.24%	5.43%
4/27/2011	10.40%	4.24%	6.16%
5/4/2011	10.00%	4.25%	5.75%
5/4/2011	10.00%	4.25%	5.75%
5/24/2011	10.50%	4.27%	6.23%
6/8/2011	10.75%	4.30%	6.45%
6/16/2011	9.20%	4.32%	4.88%
6/17/2011	9.95%	4.32%	5.63%
7/13/2011	10.20%	4.37%	5.83%
8/1/2011	9.20%	4.39%	4.81%
8/8/2011	10.00%	4.38%	5.62%
8/11/2011	10.00%	4.38%	5.62%
8/12/2011	10.35%	4.38%	5.97%
8/19/2011	10.25%	4.36%	5.89%
9/2/2011	12.88%	4.32%	8.56%
9/22/2011	10.00%	4.24%	5.76%
10/12/2011	10.30%	4.14%	6.16%
10/20/2011	10.50%	4.10%	6.40%
11/30/2011	10.90%	3.87%	7.03%
11/30/2011	10.90%	3.87%	7.03%
12/14/2011	10.00%	3.79%	6.21%
12/14/2011	10.30%	3.79%	6.51%
12/20/2011	10.20%	3.76%	6.44%
12/21/2011	10.20%	3.75%	6.45%
12/22/2011	9.90%	3.75%	6.15%
12/22/2011	10.40%	3.75%	6.65%
12/23/2011	10.19%	3.74%	6.45%
1/25/2012	10.50%	3.57%	6.93%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/27/2012	10.50%	3.55%	6.95%
2/15/2012	10.20%	3.47%	6.73%
2/23/2012	9.90%	3.43%	6.47%
2/27/2012	10.25%	3.42%	6.83%
2/29/2012	10.40%	3.41%	6.99%
3/29/2012	10.37%	3.31%	7.06%
4/4/2012	10.00%	3.29%	6.71%
4/26/2012	10.00%	3.20%	6.80%
5/2/2012	10.00%	3.18%	6.82%
5/7/2012	9.80%	3.16%	6.64%
5/15/2012	10.00%	3.14%	6.86%
5/29/2012	10.05%	3.11%	6.94%
6/7/2012	10.30%	3.07%	7.23%
6/14/2012	9.40%	3.06%	6.34%
6/15/2012	10.40%	3.06%	7.34%
6/18/2012	9.60%	3.05%	6.55%
6/19/2012	9.25%	3.05%	6.20%
6/26/2012	10.10%	3.04%	7.06%
6/29/2012	10.00%	3.04%	6.96%
7/9/2012	10.20%	3.03%	7.17%
7/16/2012	9.80%	3.02%	6.78%
7/20/2012	9.81%	3.01%	6.80%
7/20/2012	9.31%	3.01%	6.30%
9/13/2012	9.80%	2.94%	6.86%
9/19/2012	10.05%	2.94%	7.11%
9/19/2012	9.80%	2.94%	6.86%
9/26/2012	9.50%	2.94%	6.56%
10/12/2012	9.60%	2.93%	6.67%
10/23/2012	9.75%	2.93%	6.82%
10/24/2012	10.30%	2.93%	7.37%
11/9/2012	10.30%	2.92%	7.38%
11/28/2012	10.40%	2.90%	7.50%
11/29/2012	9.88%	2.89%	6.99%
11/29/2012	9.75%	2.89%	6.86%
12/5/2012	9.71%	2.89%	6.82%
12/5/2012	10.40%	2.89%	7.51%
12/12/2012	9.80%	2.88%	6.92%
12/13/2012	10.50%	2.88%	7.62%
12/13/2012	9.50%	2.88%	6.62%
12/14/2012	10.40%	2.88%	7.52%
12/19/2012	9.71%	2.87%	6.84%
12/19/2012	10.25%	2.87%	7.38%
12/20/2012	10.40%	2.87%	7.53%
12/20/2012	10.30%	2.87%	7.43%
12/20/2012	10.45%	2.87%	7.58%
12/20/2012	10.25%	2.87%	7.38%
12/20/2012	10.25%	2.87%	7.38%
12/20/2012	9.80%	2.87%	6.93%
12/20/2012	9.50%	2.87%	6.63%
12/21/2012	10.20%	2.87%	7.33%
12/26/2012	9.80%	2.86%	6.94%
1/9/2013	9.70%	2.84%	6.86%
1/9/2013	9.70%	2.84%	6.86%
1/9/2013	9.70%	2.84%	6.86%
1/16/2013	9.60%	2.84%	6.76%
1/16/2013	9.60%	2.84%	6.76%
2/13/2013	10.20%	2.84%	7.36%
2/22/2013	9.75%	2.85%	6.90%
2/27/2013	10.00%	2.86%	7.14%
3/14/2013	9.30%	2.88%	6.42%
3/27/2013	9.80%	2.90%	6.90%
5/1/2013	9.84%	2.94%	6.90%
5/15/2013	10.30%	2.96%	7.34%
5/30/2013	10.20%	2.98%	7.22%
5/31/2013	9.00%	2.98%	6.02%
6/11/2013	10.00%	3.00%	7.00%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
6/21/2013	9.75%	3.02%	6.73%
6/25/2013	9.80%	3.03%	6.77%
7/12/2013	9.36%	3.08%	6.28%
8/8/2013	9.83%	3.14%	6.69%
8/14/2013	9.15%	3.16%	5.99%
9/11/2013	10.25%	3.27%	6.98%
9/11/2013	10.20%	3.27%	6.93%
9/24/2013	10.20%	3.31%	6.89%
10/3/2013	9.65%	3.33%	6.32%
11/6/2013	10.20%	3.41%	6.79%
11/21/2013	10.00%	3.44%	6.56%
11/26/2013	10.00%	3.45%	6.55%
12/3/2013	10.25%	3.47%	6.78%
12/4/2013	9.50%	3.47%	6.03%
12/5/2013	10.20%	3.48%	6.72%
12/9/2013	8.72%	3.49%	5.23%
12/9/2013	9.75%	3.49%	6.26%
12/13/2013	9.75%	3.50%	6.25%
12/16/2013	9.95%	3.50%	6.45%
12/16/2013	9.95%	3.50%	6.45%
12/16/2013	10.12%	3.50%	6.62%
12/17/2013	9.50%	3.51%	5.99%
12/17/2013	10.95%	3.51%	7.44%
12/18/2013	8.72%	3.51%	5.21%
12/18/2013	9.80%	3.51%	6.29%
12/19/2013	10.15%	3.51%	6.64%
12/30/2013	9.50%	3.54%	5.96%
2/20/2014	9.20%	3.69%	5.51%
2/26/2014	9.75%	3.70%	6.05%
3/17/2014	9.55%	3.72%	5.83%
3/26/2014	9.40%	3.73%	5.67%
3/26/2014	9.96%	3.73%	6.23%
4/2/2014	9.70%	3.73%	5.97%
5/16/2014	9.80%	3.70%	6.10%
5/30/2014	9.70%	3.68%	6.02%
6/6/2014	10.40%	3.67%	6.73%
6/30/2014	9.55%	3.64%	5.91%
7/2/2014	9.62%	3.64%	5.98%
7/10/2014	9.95%	3.63%	6.32%
7/23/2014	9.75%	3.61%	6.14%
7/29/2014	9.45%	3.60%	5.85%
7/31/2014	9.90%	3.60%	6.30%
8/20/2014	9.75%	3.56%	6.19%
8/25/2014	9.60%	3.56%	6.04%
8/29/2014	9.80%	3.54%	6.26%
9/11/2014	9.60%	3.51%	6.09%
9/15/2014	10.25%	3.51%	6.74%
10/9/2014	9.80%	3.44%	6.36%
11/6/2014	9.56%	3.37%	6.19%
11/6/2014	10.20%	3.37%	6.83%
11/14/2014	10.20%	3.35%	6.85%
11/26/2014	9.70%	3.32%	6.38%
11/26/2014	10.20%	3.32%	6.88%
12/4/2014	9.68%	3.30%	6.38%
12/10/2014	9.25%	3.29%	5.96%
12/10/2014	9.25%	3.29%	5.96%
12/11/2014	10.07%	3.28%	6.79%
12/12/2014	10.20%	3.28%	6.92%
12/17/2014	9.17%	3.27%	5.90%
12/18/2014	9.83%	3.26%	6.57%
1/23/2015	9.50%	3.14%	6.36%
2/24/2015	9.83%	3.04%	6.79%
3/18/2015	9.75%	2.98%	6.77%
3/25/2015	9.50%	2.95%	6.55%
3/26/2015	9.72%	2.95%	6.77%
4/23/2015	10.20%	2.87%	7.33%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
4/29/2015	9.53%	2.86%	6.67%
5/1/2015	9.60%	2.85%	6.75%
5/26/2015	9.75%	2.83%	6.92%
6/17/2015	9.00%	2.82%	6.18%
6/17/2015	9.00%	2.82%	6.18%
9/2/2015	9.50%	2.79%	6.71%
9/10/2015	9.30%	2.79%	6.51%
9/25/2015	9.60%	2.80%	6.80%
10/15/2015	9.00%	2.81%	6.19%
11/19/2015	10.30%	2.88%	7.42%
11/19/2015	10.00%	2.88%	7.12%
12/3/2015	10.00%	2.90%	7.10%
12/9/2015	9.14%	2.90%	6.24%
12/9/2015	9.14%	2.90%	6.24%
12/11/2015	10.30%	2.90%	7.40%
12/15/2015	9.60%	2.91%	6.69%
12/17/2015	9.70%	2.91%	6.79%
12/18/2015	9.50%	2.91%	6.59%
12/30/2015	9.50%	2.93%	6.57%
1/6/2016	9.50%	2.94%	6.56%
2/23/2016	9.75%	2.94%	6.81%
3/16/2016	9.85%	2.91%	6.94%
4/29/2016	9.80%	2.83%	6.97%
6/3/2016	9.75%	2.80%	6.95%
6/8/2016	9.48%	2.80%	6.68%
6/15/2016	9.00%	2.78%	6.22%
6/15/2016	9.00%	2.78%	6.22%
7/18/2016	9.98%	2.71%	7.27%
8/9/2016	9.85%	2.66%	7.19%
8/18/2016	9.50%	2.63%	6.87%
8/24/2016	9.75%	2.61%	7.14%
9/1/2016	9.50%	2.59%	6.91%
9/8/2016	10.00%	2.57%	7.43%
9/28/2016	9.58%	2.53%	7.05%
9/30/2016	9.90%	2.53%	7.37%
11/9/2016	9.80%	2.48%	7.32%
11/10/2016	9.50%	2.48%	7.02%
11/15/2016	9.55%	2.49%	7.06%
11/18/2016	10.00%	2.50%	7.50%
11/29/2016	10.55%	2.51%	8.04%
12/1/2016	10.00%	2.51%	7.49%
12/6/2016	8.64%	2.52%	6.12%
12/6/2016	8.64%	2.52%	6.12%
12/7/2016	10.10%	2.52%	7.58%
12/12/2016	9.60%	2.53%	7.07%
12/14/2016	9.10%	2.53%	6.57%
12/19/2016	9.37%	2.54%	6.83%
12/19/2016	9.00%	2.54%	6.46%
12/22/2016	9.90%	2.55%	7.35%
12/22/2016	9.60%	2.55%	7.05%
12/28/2016	9.50%	2.55%	6.95%
1/18/2017	9.45%	2.58%	6.87%
1/24/2017	9.00%	2.59%	6.41%
1/31/2017	10.10%	2.60%	7.50%
2/15/2017	9.60%	2.62%	6.98%
2/22/2017	9.60%	2.64%	6.96%
2/24/2017	9.75%	2.64%	7.11%
2/28/2017	10.10%	2.64%	7.46%
3/2/2017	9.41%	2.65%	6.76%
3/20/2017	9.50%	2.68%	6.82%
4/4/2017	10.25%	2.72%	7.53%
4/12/2017	9.40%	2.74%	6.66%
4/20/2017	9.50%	2.76%	6.74%
5/3/2017	9.50%	2.79%	6.71%
5/11/2017	9.20%	2.81%	6.39%
5/18/2017	9.50%	2.83%	6.67%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
5/23/2017	9.70%	2.84%	6.86%
6/16/2017	9.65%	2.89%	6.76%
6/22/2017	9.70%	2.90%	6.80%
6/22/2017	9.70%	2.90%	6.80%
7/24/2017	9.50%	2.95%	6.55%
8/15/2017	10.00%	2.97%	7.03%
9/22/2017	9.60%	2.93%	6.67%
9/28/2017	9.80%	2.92%	6.88%
10/20/2017	9.50%	2.91%	6.59%
10/26/2017	10.25%	2.91%	7.34%
10/26/2017	10.20%	2.91%	7.29%
10/26/2017	10.30%	2.91%	7.39%
11/6/2017	10.25%	2.90%	7.35%
11/15/2017	11.95%	2.89%	9.06%
11/30/2017	10.00%	2.88%	7.12%
11/30/2017	10.00%	2.88%	7.12%
12/5/2017	9.50%	2.88%	6.62%
12/6/2017	8.40%	2.87%	5.53%
12/6/2017	8.40%	2.87%	5.53%
12/7/2017	9.80%	2.87%	6.93%
12/14/2017	9.65%	2.86%	6.79%
12/14/2017	9.60%	2.86%	6.74%
12/18/2017	9.50%	2.86%	6.64%
12/20/2017	9.58%	2.85%	6.73%
12/21/2017	9.10%	2.85%	6.25%
12/28/2017	9.50%	2.85%	6.65%
12/29/2017	9.51%	2.85%	6.66%
1/18/2018	9.70%	2.84%	6.86%
1/31/2018	9.30%	2.84%	6.46%
2/2/2018	9.98%	2.84%	7.14%
2/23/2018	9.90%	2.85%	7.05%
3/12/2018	9.25%	2.86%	6.39%
3/15/2018	9.00%	2.87%	6.13%
3/29/2018	10.00%	2.88%	7.12%
4/12/2018	9.90%	2.89%	7.01%
4/13/2018	9.73%	2.89%	6.84%
4/18/2018	9.25%	2.89%	6.36%
4/18/2018	10.00%	2.89%	7.11%
4/26/2018	9.50%	2.90%	6.60%
5/30/2018	9.95%	2.94%	7.01%
5/31/2018	9.50%	2.94%	6.56%
6/14/2018	8.80%	2.96%	5.84%
6/22/2018	9.50%	2.97%	6.53%
6/22/2018	9.90%	2.97%	6.93%
6/28/2018	9.35%	2.97%	6.38%
6/29/2018	9.50%	2.97%	6.53%
8/8/2018	9.53%	2.99%	6.54%
8/21/2018	9.70%	3.00%	6.70%
8/24/2018	9.28%	3.01%	6.27%
9/5/2018	9.56%	3.02%	6.54%
9/14/2018	10.00%	3.03%	6.97%
9/20/2018	9.80%	3.04%	6.76%
9/26/2018	9.77%	3.05%	6.72%
9/26/2018	10.00%	3.05%	6.95%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
9/27/2018	9.30%	3.05%	6.25%
10/4/2018	9.85%	3.06%	6.79%
10/29/2018	9.60%	3.10%	6.50%
10/31/2018	9.99%	3.11%	6.88%
11/1/2018	8.69%	3.11%	5.58%
12/4/2018	8.69%	3.14%	5.55%
12/13/2018	9.30%	3.14%	6.16%
12/14/2018	9.50%	3.14%	6.36%
12/19/2018	9.84%	3.14%	6.70%
12/20/2018	9.65%	3.14%	6.51%
12/21/2018	9.30%	3.14%	6.16%
1/9/2019	10.00%	3.14%	6.86%
2/27/2019	9.75%	3.12%	6.63%
3/13/2019	9.60%	3.12%	6.48%
3/14/2019	9.00%	3.12%	5.88%
3/14/2019	9.40%	3.12%	6.28%
3/22/2019	9.65%	3.12%	6.53%
4/30/2019	9.73%	3.11%	6.62%
4/30/2019	9.73%	3.11%	6.62%
5/1/2019	9.50%	3.11%	6.39%
5/2/2019	10.00%	3.11%	6.89%
5/8/2019	9.50%	3.10%	6.40%
5/14/2019	8.75%	3.10%	5.65%
5/16/2019	9.50%	3.09%	6.41%
5/23/2019	9.90%	3.09%	6.81%
8/12/2019	9.60%	2.89%	6.71%
8/29/2019	9.06%	2.81%	6.25%
9/4/2019	10.00%	2.78%	7.22%
9/30/2019	9.60%	2.70%	6.90%
10/31/2019	10.00%	2.60%	7.40%
10/31/2019	10.00%	2.60%	7.40%
11/7/2019	9.35%	2.58%	6.77%
11/29/2019	9.50%	2.52%	6.98%
12/4/2019	8.91%	2.51%	6.40%
12/4/2019	9.75%	2.51%	7.24%
12/16/2019	8.91%	2.48%	6.43%
12/17/2019	10.50%	2.47%	8.03%
12/17/2019	9.70%	2.47%	7.23%
12/19/2019	10.25%	2.47%	7.78%
12/19/2019	10.20%	2.47%	7.73%
12/19/2019	10.30%	2.47%	7.83%
12/20/2019	9.45%	2.46%	6.99%
12/20/2019	9.65%	2.46%	7.19%
12/24/2019	9.50%	2.46%	7.04%
1/8/2020	10.02%	2.43%	7.59%
1/16/2020	8.80%	2.41%	6.39%
1/22/2020	9.50%	2.39%	7.11%
1/23/2020	9.86%	2.39%	7.47%
2/6/2020	10.00%	2.34%	7.66%
2/11/2020	9.30%	2.33%	6.97%
2/14/2020	9.40%	2.32%	7.08%
2/19/2020	8.25%	2.31%	5.94%
2/24/2020	9.75%	2.29%	7.46%
2/27/2020	9.40%	2.28%	7.12%
3/11/2020	9.70%	2.23%	7.47%
3/25/2020	9.40%	2.17%	7.23%
4/17/2020	9.70%	2.07%	7.63%
4/27/2020	9.25%	2.02%	7.23%
5/8/2020	9.90%	1.97%	7.93%
5/20/2020	9.45%	1.94%	7.51%
6/29/2020	9.70%	1.85%	7.85%
6/30/2020	9.10%	1.85%	7.25%
7/1/2020	9.25%	1.84%	7.41%
7/8/2020	9.40%	1.82%	7.58%
7/14/2020	9.60%	1.81%	7.79%
7/28/2020	9.50%	1.76%	7.74%

Date of Electric Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
8/27/2020	10.00%	1.66%	8.34%
8/27/2020	9.45%	1.66%	7.79%
8/27/2020	8.20%	1.66%	6.54%
10/22/2020	9.50%	1.49%	8.01%
10/28/2020	9.60%	1.48%	8.12%
11/19/2020	8.80%	1.45%	7.35%
11/19/2020	8.80%	1.45%	7.35%
11/24/2020	9.80%	1.44%	8.36%
11/24/2020	9.20%	1.44%	7.76%
12/9/2020	8.38%	1.43%	6.95%
12/9/2020	8.38%	1.43%	6.95%
12/10/2020	9.40%	1.43%	7.97%
12/14/2020	9.50%	1.44%	8.06%
12/15/2020	9.30%	1.44%	7.86%
12/16/2020	9.50%	1.44%	8.06%
12/17/2020	9.90%	1.44%	8.46%
12/18/2020	9.50%	1.44%	8.06%
12/22/2020	9.15%	1.44%	7.71%
12/23/2020	10.00%	1.44%	8.56%
12/30/2020	9.65%	1.45%	8.20%
1/13/2021	9.30%	1.47%	7.83%
		# of Cases:	1,657

Small Size Premium

	[1] ($Mil)
UES Equity	$119.58
Median Market to Book for Proxy Group	1.79
UES's Implied Market Cap	$214.19

Company Name	Ticker	[2] Market Cap ($Mil)	[3] Market to Book Ratio
ALLETE, Inc.	ALE	$ 3,371.47	1.48
Alliant Energy Corporation	LNT	$ 12,173.98	2.13
Ameren Corporation	AEE	$ 18,152.67	2.11
American Electric Power Company, Inc.	AEP	$ 39,659.96	1.95
Avista Corporation	AVA	$ 2,665.08	1.34
CMS Energy Corporation	CMS	$ 16,342.48	3.02
Consolidated Edison, Inc.	ED	$ 23,882.64	1.26
DTE Energy Company	DTE	$ 23,475.35	1.90
Duke Energy Corporation	DUK	$ 68,066.71	1.52
Entergy Corporation	ETR	$ 18,783.07	1.74
Evergy, Inc	EVRG	$ 12,265.75	1.39
Eversource Energy	ES	$ 29,395.90	2.10
Hawaiian Electric Industries, Inc.	HE	$ 3,750.35	1.61
IDACORP, Inc.	IDA	$ 4,452.00	1.74
NextEra Energy, Inc.	NEE	$ 159,311.69	4.34
NorthWestern Corporation	NWE	$ 2,876.14	1.39
OGE Energy Corp.	OGE	$ 6,232.89	1.70
Otter Tail Corporation	OTTR	$ 1,706.02	1.99
Pinnacle West Capital Corporation	PNW	$ 8,599.40	1.48
Portland General Electric Company	POR	$ 3,797.46	1.46
Public Service Enterprise Group Incorporated	PEG	$ 29,264.32	1.84
Southern Company	SO	$ 63,011.62	2.23
WEC Energy Group, Inc.	WEC	$ 27,085.10	2.59
Xcel Energy Inc.	XEL	$ 33,805.09	2.34
MEDIAN		$ 17,247.57	1.79
MEAN		$ 25,505.30	1.94

Market Capitalization ($Mil) [4]			
Decile	Low	High	Size Premium
2	$ 13,178.743	$ 28,808.073	0.49%
3	$ 6,743.361	$ 13,177.828	0.71%
4	$ 3,861.858	$ 6,710.676	0.75%
5	$ 2,445.693	$ 3,836.536	1.09%
6	$ 1,591.865	$ 2,444.745	1.37%
7	$ 911.586	$ 1,591.765	1.54%
8	$ 451.955	$ 911.103	1.46%
9	$ 190.019	$ 451.800	2.29%
10	$ 2.194	$ 189.831	5.01%

Proxy Group Median	$ 17,247.574	0.49%
9th Decile Size Premium	$ 214.194	2.29%
Difference from Proxy Group Median		1.80%

Notes:
[1] UES rate base of $226 million mutiplied by the proposed common equity ratio of 52.91%
[2] Source: S&P Global Market Intelligence, 30-day average
[3] Source: S&P Global Market Intelligence, 30-day average
[4] Source: Duff & Phelps Cost of Capital Navigator, CRSP Deciles Size Premia as of December 31, 2020

			Adjustment Clauses						
Company	Parent	State (Jurisdiction)	Fuel/ Purchased Power	Decoupling (F/P) [1]	New Capital Investment [2]	Energy Efficiency [3]	Renewables & RPS [4]	Environmental [5]	Other [6]
Ameren Illinois Company	AEE	Illinois	✓	F	✓	✓	✓	✓	✓
Union Electric Company	AEE	Missouri	✓	P	✓	✓	✓	✓	✓
Southwestern Electric Power Company	AEP	Arkansas	✓	P	✓	✓		✓	✓
Indiana Michigan Power Company	AEP	Indiana	✓	P	✓	✓	✓	✓	✓
Kentucky Power Company	AEP	Kentucky	✓	P		✓		✓	✓
Southwestern Electric Power Company	AEP	Louisiana	✓	P	✓	✓		✓	✓
Indiana Michigan Power Company	AEP	Michigan	✓	P		✓	✓	✓	✓
Ohio Power Company	AEP	Ohio	✓	P	✓	✓	✓		✓
Public Service Company of Oklahoma	AEP	Oklahoma	✓	P	✓	✓			✓
Kingsport Power Company	AEP	Tennessee	✓						✓
AEP Texas Inc.	AEP	Texas	NA		✓	✓		✓	✓
Southwestern Electric Power Company	AEP	Texas	✓		✓	✓	✓		✓
Appalachian Power Company	AEP	Virginia	✓		✓	✓	✓	✓	✓
Appalachian Power / Wheeling Power	AEP	West Virginia	✓		✓	✓			✓
ALLETE (Minnesota Power)	ALE	Minnesota	✓			✓	✓	✓	✓
Superior Water, Light and Power Company	ALE	Wisconsin	✓						✓
Alaska Electric Light and Power Company	AVA	Alaska	✓						✓
Avista Corporation	AVA	Idaho	✓	F		✓			✓
Avista Corporation	AVA	Washington	✓	F		✓			✓
Consumers Energy Company	CMS	Michigan	✓			✓	✓		✓
DTE Electric Company	DTE	Michigan	✓			✓	✓	✓	✓
Duke Energy Florida, LLC	DUK	Florida	✓		✓	✓		✓	✓
Duke Energy Indiana, LLC	DUK	Indiana	✓	P	✓	✓	✓	✓	✓
Duke Energy Kentucky, Inc.	DUK	Kentucky	✓	P		✓		✓	✓
Duke Energy Carolinas, LLC	DUK	North Carolina	✓	P		✓	✓	✓	✓
Duke Energy Progress, LLC	DUK	North Carolina	✓	P	✓	✓	✓	✓	✓
Duke Energy Ohio, Inc.	DUK	Ohio	✓	P	✓	✓	✓		✓
Duke Energy Carolinas, LLC	DUK	South Carolina	✓	P		✓	✓	✓	✓
Duke Energy Progress, LLC	DUK	South Carolina	✓	P		✓	✓	✓	✓
Rockland Electric Company	ED	New Jersey	✓		✓	✓	✓		✓
Consolidated Edison Company of New York, Inc.	ED	New York	✓	F	✓	✓	✓	✓	✓
Orange and Rockland Utilities, Inc.	ED	New York	✓	F	✓	✓	✓		✓
Entergy Arkansas, Inc.	ETR	Arkansas	✓	P	✓	✓		✓	✓
Entergy Louisiana, LLC	ETR	Louisiana	✓	P	✓	✓		✓	✓
Entergy Mississippi, Inc.	ETR	Mississippi	✓	P	✓	✓			✓
Entergy New Orleans, Inc.	ETR	Louisiana - NOCC	✓	F	✓	✓		✓	✓
Entergy Texas, Inc.	ETR	Texas	✓		✓	✓			✓
Evergy Kansas Central	EVRG	Kansas	✓	P		✓		✓	✓
Evergy Kansas Metro	EVRG	Kansas	✓			✓		✓	✓
Evergy Missouri Metro	EVRG	Missouri	✓	P	✓	✓		✓	✓
Evergy Missouri West	EVRG	Missouri	✓	P	✓	✓	✓	✓	✓
Connecticut Light and Power Company	ES	Connecticut	✓	F	✓	✓		✓	✓
NSTAR Electric Company	ES	Massachusetts	✓	F	✓	✓	✓		✓
Public Service Company of New Hampshire	ES	New Hampshire	✓	P	✓	✓			✓
Hawaii Electric Light Company, Inc.	HE	Hawaii	✓	F	✓	✓	✓		✓
Hawaiian Electric Company, Inc.	HE	Hawaii	✓	F	✓	✓	✓		✓
Maui Electric Company, Limited	HE	Hawaii	✓	F	✓	✓	✓		✓
Idaho Power Co.	IDA	Idaho	✓	F		✓			✓
Idaho Power Co.	IDA	Oregon	✓			✓	✓	✓	✓
Interstate Power and Light Company	LNT	Iowa	✓			✓	✓	✓	✓
Wisconsin Power and Light Company	LNT	Wisconsin	✓						✓
Florida Power & Light Company	NEE	Florida	✓		✓	✓		✓	✓
Gulf Power Company	NEE	Florida	✓		✓	✓		✓	✓
NorthWestern Energy	NWE	Montana	✓			✓			✓
NorthWestern Energy	NWE	South Dakota	✓	P				✓	✓
Oklahoma Gas and Electric Company	OGE	Arkansas	✓	P	✓	✓		✓	✓
Oklahoma Gas and Electric Company	OGE	Oklahoma	✓	P	✓	✓			✓
Otter Tail Power Company	OTTR	Minnesota	✓		✓	✓	✓	✓	✓
Otter Tail Power Company	OTTR	North Dakota	✓		✓		✓	✓	✓
Otter Tail Power Company	OTTR	South Dakota	✓		✓	✓		✓	✓
Public Service Electric and Gas Company	PEG	New Jersey	✓		✓	✓	✓	✓	✓
Arizona Public Service Company	PNW	Arizona	✓	P		✓	✓	✓	✓
Portland General Electric Company	POR	Oregon	✓	F	✓	✓	✓	✓	✓
Alabama Power Company	SO	Alabama	✓		✓			✓	✓
Georgia Power Company	SO	Georgia	✓		✓	✓		✓	✓
Mississippi Power Company	SO	Mississippi	✓	P	✓	✓	✓	✓	✓
Upper Michigan Energy Resources Corp	WEC	Michigan	✓				✓		✓
Wisconsin Electric Power	WEC	Wisconsin	✓						✓
Wisconsin Public Service Company	WEC	Wisconsin	✓						✓
Public Service Company of Colorado	XEL	Colorado	✓	P	✓	✓	✓	✓	✓
Northern States Power Company - WI	XEL	Michigan	✓				✓		✓
Northern States Power Company - MN	XEL	Minnesota	✓	F	✓	✓	✓	✓	✓
Southwestern Public Service Company	XEL	New Mexico	✓		✓		✓		✓
Northern States Power Company - MN	XEL	North Dakota	✓	P		✓	✓		✓
Northern States Power Company - MN	XEL	South Dakota	✓	P	✓	✓		✓	✓
Southwestern Public Service Company	XEL	Texas	✓		✓	✓			✓
Northern States Power Company - WI	XEL	Wisconsin	✓						✓

			Alternative Regulation / Incentive Plans				
Company	Parent	State (Jurisdiction)	Formula-Based Rates / Formulaic ROE	Multiyear Rate Plan / Performance Based Ratemaking	Incentive ROEs/ Cost Savings Sharing / Performance Incentives [7]	Forward Test Year Allowed in Jurisdiction [8]	Earnings Sharing
Ameren Illinois Company	AEE	Illinois	✓				
Union Electric Company	AEE	Missouri			✓	K	
Southwestern Electric Power Company	AEP	Arkansas	✓		✓	✓	
Indiana Michigan Power Company	AEP	Indiana		✓	✓	✓	
Kentucky Power Company	AEP	Kentucky			✓	✓	
Southwestern Electric Power Company	AEP	Louisiana	✓		✓	K	✓
Indiana Michigan Power Company	AEP	Michigan				✓	
Ohio Power Company	AEP	Ohio		✓	✓	K	
Public Service Company of Oklahoma	AEP	Oklahoma			✓	K	
Kingsport Power Company	AEP	Tennessee				✓	
AEP Texas Inc.	AEP	Texas				K	
Southwestern Electric Power Company	AEP	Texas				K	
Appalachian Power Company	AEP	Virginia	✓		✓	✓	✓
Appalachian Power / Wheeling Power	AEP	West Virginia				K	
ALLETE (Minnesota Power)	ALE	Minnesota			✓	✓	
Superior Water, Light and Power Company	ALE	Wisconsin				✓	
Alaska Electric Light and Power Company	AVA	Alaska					
Avista Corporation	AVA	Idaho			✓	✓	
Avista Corporation	AVA	Washington			✓	K	
Consumers Energy Company	CMS	Michigan				✓	
DTE Electric Company	DTE	Michigan				✓	
Duke Energy Florida, LLC	DUK	Florida		✓	✓	✓	
Duke Energy Indiana, LLC	DUK	Indiana			✓	✓	
Duke Energy Kentucky, Inc.	DUK	Kentucky			✓	✓	
Duke Energy Carolinas, LLC	DUK	North Carolina			✓	K	
Duke Energy Progress, LLC	DUK	North Carolina			✓	K	
Duke Energy Ohio, Inc.	DUK	Ohio		✓	✓	K	
Duke Energy Carolinas, LLC	DUK	South Carolina			✓		
Duke Energy Progress, LLC	DUK	South Carolina			✓		
Rockland Electric Company	ED	New Jersey				K	
Consolidated Edison Company of New York, Inc.	ED	New York		✓	✓	✓	✓
Orange and Rockland Utilities, Inc.	ED	New York		✓	✓	✓	✓
Entergy Arkansas, Inc.	ETR	Arkansas	✓		✓	✓	✓
Entergy Louisiana, LLC	ETR	Louisiana	✓		✓	K	✓
Entergy Mississippi, Inc.	ETR	Mississippi	✓		✓	✓	✓
Entergy New Orleans, Inc.	ETR	Louisiana - NOCC	✓	✓		✓	✓
Entergy Texas, Inc.	ETR	Texas					
Evergy Kansas Central	EVRG	Kansas				K	✓
Evergy Kansas Metro	EVRG	Kansas			✓	K	✓
Evergy Missouri Metro	EVRG	Missouri			✓	K	
Evergy Missouri West	EVRG	Missouri			✓	K	
Connecticut Light and Power Company	ES	Connecticut		✓	✓	✓	✓
NSTAR Electric Company	ES	Massachusetts	✓	✓	✓	K	✓
Public Service Company of New Hampshire	ES	New Hampshire				K	
Hawaii Electric Light Company, Inc.	HE	Hawaii	✓	✓	✓	✓	✓
Hawaiian Electric Company, Inc.	HE	Hawaii	✓	✓	✓	✓	✓
Maui Electric Company, Limited	HE	Hawaii	✓	✓	✓	✓	✓
Idaho Power Co.	IDA	Idaho				✓	✓
Idaho Power Co.	IDA	Oregon				✓	
Interstate Power and Light Company	LNT	Iowa			✓	K	
Wisconsin Power and Light Company	LNT	Wisconsin		✓	✓	✓	
Florida Power & Light Company	NEE	Florida		✓	✓	✓	✓
Gulf Power Company	NEE	Florida			✓	✓	
NorthWestern Energy	NWE	Montana			✓	K	
NorthWestern Energy	NWE	South Dakota			✓	K	
Oklahoma Gas and Electric Company	OGE	Arkansas	✓		✓	✓	✓
Oklahoma Gas and Electric Company	OGE	Oklahoma			✓	K	
Otter Tail Power Company	OTTR	Minnesota			✓	✓	
Otter Tail Power Company	OTTR	North Dakota			✓	✓	
Otter Tail Power Company	OTTR	South Dakota				K	✓
Public Service Electric and Gas Company	PEG	New Jersey					
Arizona Public Service Company	PNW	Arizona				K	
Portland General Electric Company	POR	Oregon				✓	
Alabama Power Company	SO	Alabama	✓		✓	K	✓
Georgia Power Company	SO	Georgia	✓	✓	✓	✓	✓
Mississippi Power Company	SO	Mississippi	✓		✓	✓	✓
Upper Michigan Energy Resources Corp	WEC	Michigan				✓	
Wisconsin Electric Power	WEC	Wisconsin		✓	✓	✓	✓
Wisconsin Public Service Company	WEC	Wisconsin		✓	✓	✓	✓
Public Service Company of Colorado	XEL	Colorado			✓		
Northern States Power Company - WI	XEL	Michigan		✓		✓	
Northern States Power Company - MN	XEL	Minnesota	✓	✓	✓	✓	
Southwestern Public Service Company	XEL	New Mexico					
Northern States Power Company - MN	XEL	North Dakota			✓	✓	✓
Northern States Power Company - MN	XEL	South Dakota			✓	K	✓
Southwestern Public Service Company	XEL	Texas				K	
Northern States Power Company - WI	XEL	Wisconsin			✓	✓	✓

Notes:

A mechanism may cover one or more cost categories; therefore, designations may not indicate separate mechanisms for each category. Texas T&D utilities do not have retail obligation, thus do not need a fuel or purchased power cost recovery mechanism.

[1] Full or partial decoupling (such as Straight-Fixed Variable rate design, weather normalization clauses, and recovery of lost revenues as a result of Energy Efficiency programs).

[2] Includes recovery of costs related to targeted new generation projects, infrastructure replacement, system integrity/hardening, Smart Grid, AMI metering, and other capital expenditures.

[3] Utility-sponsored conservation, energy efficiency, load control, or other demand side management programs.

[4] Recovers costs associated with renewable energy projects, Distributed Energy Resources, REC purchases, net metering, RPS expense, and renewable PPAs.

[5] EPA upgrade costs, emissions control & allowance purchase costs, nuclear/coal plant decommissioning, and other costs to comply with state and federal environmental mandates.

[6] Cost recovery for items such as pension expenses, bad debt costs, storm costs, vegetation management, RTO/Transmission Expense, capacity costs, transmission costs, government & franchise fees and taxes, economic development, and low income programs.

[7] Includes incentive ROE adders, cost savings sharing and performance incentives (e.g., Fuel/Purchased Power savings; Capacity release/OSS savings; and fincancial incentives for performance including meeting Demand Side Management/Energy Efficiency, Reliability, and other

[8] Partially forecasted test years are included. K = Known and measurable changes allowed

Sources: Alternative Ratemaking Plans in the U.S., Regulatory Research Associates, April 16, 2020; Regulatory Research Associates, Adjustment Clauses: A State-by-State Overview, November 12, 2019; ACEEE Utility Business Model Database; Regulatory Research Associates Commission Profiles; SEC Form 10-Ks; Company Tariffs.

Proxy Group Capital Structure

		% Common Equity									
Company	Ticker	2020Q3	2020Q2	2020Q1	2019Q4	2019Q3	2019Q2	2019Q1	2018Q4	5Q Average	8Q Average
ALLETE, Inc.	ALE	56.62%	57.24%	58.73%	58.84%	58.68%	59.66%	59.53%	59.12%	58.02%	58.55%
Alliant Energy Corporation	LNT	51.73%	50.68%	52.20%	51.26%	50.98%	49.56%	52.31%	52.20%	51.37%	51.36%
Ameren Corporation	AEE	51.59%	52.85%	51.49%	51.98%	53.18%	52.54%	52.32%	52.19%	52.22%	52.27%
American Electric Power Company, Inc.	AEP	49.59%	49.41%	49.33%	49.75%	49.91%	48.80%	49.62%	49.40%	49.60%	49.48%
Avista Corporation	AVA	60.67%	55.98%	55.74%	55.22%	55.80%	56.32%	56.10%	55.09%	56.69%	56.37%
CMS Energy Corporation	CMS	51.44%	50.01%	49.69%	51.33%	51.57%	53.50%	52.38%	50.14%	50.81%	51.26%
Consolidated Edison, Inc.	ED	47.12%	47.60%	47.52%	48.23%	49.85%	49.08%	48.75%	47.97%	48.06%	48.26%
DTE Energy Company	DTE	48.83%	45.65%	47.27%	50.04%	49.40%	48.76%	48.69%	50.96%	48.24%	48.70%
Duke Energy Corporation	DUK	53.27%	53.02%	53.21%	53.46%	52.89%	54.48%	53.14%	54.35%	53.17%	53.48%
Entergy Corporation	ETR	47.62%	47.43%	47.41%	48.63%	49.00%	48.19%	48.81%	50.11%	48.02%	48.40%
Evergy, Inc	EVRG	60.30%	59.21%	60.11%	60.14%	60.28%	60.51%	58.16%	59.56%	60.01%	59.78%
Eversource Energy	ES	52.73%	52.44%	51.78%	52.43%	49.15%	48.99%	53.79%	52.87%	51.71%	51.77%
Hawaiian Electric Industries, Inc.	HE	56.67%	56.06%	56.13%	57.12%	57.77%	57.51%	57.40%	57.32%	56.75%	57.00%
IDACORP, Inc.	IDA	54.04%	51.25%	55.18%	55.14%	55.20%	54.58%	54.36%	54.25%	54.16%	54.25%
NextEra Energy, Inc.	NEE	61.82%	62.33%	58.06%	55.27%	56.15%	61.22%	64.03%	64.37%	58.73%	60.41%
NorthWestern Corporation	NWE	48.26%	48.61%	47.78%	47.59%	47.80%	48.07%	48.74%	47.88%	48.01%	48.09%
OGE Energy Corp.	OGE	52.78%	53.09%	55.28%	55.15%	54.96%	53.47%	55.38%	53.20%	54.25%	54.16%
Otter Tail Corporation	OTTR	52.72%	52.84%	50.85%	51.12%	55.43%	53.75%	53.90%	53.58%	52.59%	53.03%
Pinnacle West Capital Corporation	PNW	51.58%	51.89%	53.66%	52.80%	54.25%	54.41%	54.48%	54.36%	52.83%	53.43%
Portland General Electric Company	POR	47.85%	48.33%	50.09%	49.85%	51.78%	51.56%	50.60%	50.19%	49.58%	50.03%
Public Service Enterprise Group Incorporated	PEG	53.83%	53.46%	53.77%	54.72%	54.65%	54.31%	55.14%	54.24%	54.09%	54.26%
Southern Company	SO	54.42%	53.91%	54.25%	52.40%	52.07%	52.63%	53.88%	53.99%	53.41%	53.44%
WEC Energy Group, Inc.	WEC	56.37%	55.74%	55.17%	55.35%	55.70%	56.62%	55.64%	53.37%	55.67%	55.49%
Xcel Energy Inc.	XEL	54.01%	52.89%	54.54%	54.22%	53.98%	54.70%	54.51%	54.22%	53.93%	54.14%
Mean		53.16%	52.58%	52.89%	53.00%	53.35%	53.47%	53.82%	53.54%	53.00%	53.23%
Median		52.75%	52.85%	53.44%	52.61%	53.58%	53.62%	53.89%	53.48%	53.00%	53.44%

Operating Company Capital Structure

		% Common Equity									
Operating Company	Parent	2020Q3	2020Q2	2020Q1	2019Q4	2019Q3	2019Q2	2019Q1	2018Q4	5Q Average	8Q Average
Ameren Illinois Company	AEE	NA	55.74%	53.89%	52.58%	54.01%	53.59%	53.19%	52.40%	54.05%	53.63%
Union Electric Company	AEE	51.59%	49.96%	49.08%	51.39%	52.36%	51.49%	51.45%	51.98%	50.88%	51.16%
AEP Texas Inc.	AEP	42.06%	45.04%	44.16%	43.77%	46.97%	46.32%	47.54%	45.38%	44.40%	45.15%
Appalachian Power Company	AEP	47.10%	46.65%	49.16%	48.74%	48.74%	48.19%	47.77%	49.51%	48.08%	48.23%
Indiana Michigan Power Company	AEP	48.35%	47.83%	47.42%	46.74%	46.51%	45.83%	45.43%	44.62%	47.37%	46.59%
Kentucky Power Company	AEP	44.88%	44.57%	44.60%	47.34%	46.94%	46.50%	46.42%	45.72%	45.67%	45.87%
Kingsport Power Company	AEP	55.42%	54.98%	55.04%	54.62%	54.24%	50.18%	51.54%	50.79%	54.86%	53.35%
Ohio Power Company	AEP	52.10%	51.75%	51.18%	54.50%	53.63%	52.92%	58.86%	57.80%	52.63%	54.09%
Public Service Company of Oklahoma	AEP	51.95%	50.57%	49.51%	49.69%	49.89%	48.02%	47.19%	49.16%	50.32%	49.50%
Southwestern Electric Power Company	AEP	50.57%	49.71%	48.97%	48.80%	48.63%	47.45%	47.59%	46.97%	49.33%	48.59%
Wheeling Power Company	AEP	53.86%	53.55%	53.89%	53.51%	53.66%	53.83%	54.27%	54.62%	53.70%	53.90%
ALLETE (Minnesota Power)	ALE	54.30%	55.80%	58.32%	59.59%	59.33%	60.94%	60.87%	61.39%	57.47%	58.82%
Superior Water, Light and Power Company	ALE	58.94%	58.68%	59.14%	58.08%	58.03%	58.38%	58.19%	56.86%	58.58%	58.29%
Alaska Electric Light and Power Company	AVA	60.67%	60.62%	60.34%	59.62%	61.28%	61.24%	61.02%	60.29%	60.51%	60.63%
Avista Corporation	AVA	NA	51.35%	51.15%	50.83%	50.33%	51.40%	51.18%	49.89%	50.91%	50.87%
Consumers Energy Company	CMS	51.44%	50.01%	49.69%	51.33%	51.57%	53.50%	52.38%	50.14%	50.81%	51.26%
DTE Electric Company	DTE	48.83%	45.65%	47.27%	50.04%	49.40%	48.76%	48.69%	50.96%	48.24%	48.70%
Duke Energy Carolinas, LLC	DUK	51.93%	51.56%	50.26%	52.11%	51.80%	52.94%	52.32%	51.78%	51.53%	51.84%
Duke Energy Florida, LLC	DUK	52.10%	51.12%	51.30%	49.91%	52.82%	51.55%	50.56%	50.04%	51.45%	51.17%
Duke Energy Indiana, LLC	DUK	53.08%	50.12%	50.22%	52.84%	51.52%	54.83%	54.29%	53.26%	51.56%	52.52%
Duke Energy Kentucky, Inc.	DUK	49.28%	51.35%	50.07%	49.37%	45.44%	53.04%	52.81%	51.95%	49.10%	50.41%
Duke Energy Ohio, Inc.	DUK	62.16%	61.73%	65.61%	65.22%	64.90%	64.45%	59.29%	68.09%	63.92%	63.93%
Duke Energy Progress, LLC	DUK	51.10%	52.23%	51.82%	51.29%	50.86%	50.09%	49.60%	51.00%	51.46%	51.00%
Consolidated Edison Company of New York, In	ED	47.17%	46.64%	46.23%	48.41%	49.29%	48.92%	48.30%	47.52%	47.55%	47.81%
Orange and Rockland Utilities, Inc.	ED	47.06%	48.57%	48.82%	48.05%	50.40%	49.25%	49.21%	48.41%	48.58%	48.72%
Rockland Electric Company	ED	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Connecticut Light and Power Company	ES	56.72%	55.43%	54.79%	54.53%	53.32%	54.53%	57.26%	55.32%	54.96%	55.24%
Public Service Company of New Hampshire	ES	47.60%	48.99%	48.26%	47.77%	40.64%	40.02%	48.38%	47.92%	46.65%	46.20%
NSTAR Electric Company	ES	53.85%	52.88%	52.29%	55.00%	53.50%	52.43%	55.73%	55.38%	53.51%	53.88%
Entergy Arkansas, LLC	ETR	44.42%	47.93%	47.46%	47.90%	47.72%	46.49%	47.04%	49.42%	47.09%	47.30%
Entergy Louisiana, LLC	ETR	48.23%	46.62%	46.00%	47.47%	47.13%	46.32%	45.79%	47.37%	47.09%	46.87%
Entergy Mississippi, LLC	ETR	47.91%	47.09%	48.92%	48.60%	48.35%	44.93%	49.41%	49.11%	48.18%	48.04%
Entergy New Orleans, LLC	ETR	45.74%	44.82%	44.58%	49.26%	53.69%	52.40%	51.69%	51.19%	47.62%	49.17%
Entergy Texas, Inc.	ETR	51.82%	50.71%	50.08%	49.93%	48.13%	50.79%	50.13%	53.46%	50.13%	50.63%
Evergy Kansas South, Inc.	EVRG	82.55%	82.18%	82.03%	81.96%	81.84%	81.49%	75.13%	74.97%	82.11%	80.27%
Evergy Metro, Inc.	EVRG	48.77%	47.12%	49.97%	50.31%	50.43%	49.62%	46.04%	49.49%	49.32%	48.97%
Evergy Missouri West, Inc.	EVRG	52.91%	51.74%	50.52%	50.34%	51.18%	51.74%	52.68%	54.71%	51.34%	51.98%
Westar Energy (KPL)	EVRG	56.97%	55.81%	57.92%	57.97%	57.66%	59.18%	58.80%	59.08%	57.27%	57.93%
Hawaii Electric Light Company, Inc.	HE	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Hawaiian Electric Company, Inc.	HE	56.67%	56.06%	56.13%	57.12%	57.77%	57.51%	57.40%	57.32%	56.75%	57.00%
Maui Electric Company, Limited	HE	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Idaho Power Company	IDA	54.04%	51.25%	55.18%	55.14%	55.20%	54.58%	54.36%	54.25%	54.16%	54.25%
Interstate Power and Light Company	LNT	50.68%	48.89%	49.75%	48.74%	48.56%	50.11%	51.59%	51.70%	49.32%	50.00%
Wisconsin Power and Light Company	LNT	52.78%	52.47%	54.64%	53.78%	53.40%	49.01%	53.03%	52.69%	53.41%	52.72%
Florida Power & Light Company	NEE	59.99%	63.16%	60.14%	60.24%	59.78%	61.30%	64.03%	64.37%	60.66%	61.63%
Gulf Power Company	NEE	63.66%	61.51%	55.97%	50.30%	52.52%	61.15%	NA	NA	56.79%	57.52%
NorthWestern Corporation	NWE	48.26%	48.61%	47.78%	47.59%	47.80%	48.07%	48.74%	47.88%	48.01%	48.09%
Oklahoma Gas and Electric Company	OGE	52.78%	53.09%	55.28%	55.15%	54.96%	53.47%	55.38%	53.20%	54.25%	54.16%
Otter Tail Power Company	OTTR	52.72%	52.84%	50.85%	51.12%	55.43%	53.75%	53.90%	53.58%	52.59%	53.03%
Public Service Electric and Gas Company	PEG	53.83%	53.46%	53.77%	54.72%	54.65%	54.31%	55.14%	54.24%	54.09%	54.26%
Arizona Public Service Company	PNW	51.58%	51.89%	53.66%	52.80%	54.25%	54.41%	54.48%	54.36%	52.83%	53.43%
Portland General Electric Company	POR	47.85%	48.33%	50.09%	49.85%	51.78%	51.56%	50.60%	50.19%	49.58%	50.03%
Alabama Power Company	SO	51.15%	52.15%	52.24%	50.23%	50.60%	51.63%	51.31%	46.88%	51.27%	50.77%
Georgia Power Company	SO	56.59%	54.59%	55.70%	56.12%	55.38%	56.39%	56.43%	59.02%	55.68%	56.28%
Gulf Power Company	SO	NA	NA	NA	NA	NA	NA	58.06%	59.73%	NA	58.89%
Mississippi Power Company	SO	55.53%	54.99%	54.80%	50.84%	50.23%	49.87%	49.73%	50.35%	53.28%	52.04%
Upper Michigan Energy Resources Corporatior	WEC	54.10%	53.52%	52.81%	55.45%	56.09%	54.45%	52.54%	47.01%	54.39%	53.25%
Wisconsin Electric Power Company	WEC	57.70%	56.92%	56.41%	56.00%	56.64%	56.37%	55.50%	55.76%	56.74%	56.41%
Wisconsin Public Service Corporation	WEC	57.29%	56.78%	56.29%	54.61%	54.37%	59.04%	58.88%	57.33%	55.87%	56.82%
Northern States Power Company - MN	XEL	52.20%	50.13%	52.55%	52.20%	51.79%	53.66%	53.64%	52.81%	51.78%	52.37%
Northern States Power Company - WI	XEL	53.13%	52.61%	54.90%	54.23%	53.56%	53.49%	53.59%	53.60%	53.68%	53.64%
Public Service Company of Colorado	XEL	56.56%	54.60%	56.58%	56.32%	56.35%	57.53%	56.68%	56.31%	56.08%	56.37%
Southwestern Public Service Company	XEL	54.15%	54.22%	54.13%	54.14%	54.21%	54.14%	54.13%	54.17%	54.17%	54.16%
Mean		52.92%	52.53%	52.71%	52.82%	52.91%	53.04%	53.17%	53.13%	52.77%	52.99%
Median		52.20%	51.75%	51.82%	51.39%	52.52%	52.92%	52.68%	52.40%	51.78%	52.45%

Source: S&P Global Market Intelligence

Proxy Group Capital Structure

		% Long-Term Debt									
Company	Ticker	2020Q3	2020Q2	2020Q1	2019Q4	2019Q3	2019Q2	2019Q1	2018Q4	5Q Average	8Q Average
ALLETE, Inc.	ALE	43.38%	42.76%	41.27%	41.16%	41.32%	40.34%	40.47%	40.88%	41.98%	41.45%
Alliant Energy Corporation	LNT	46.91%	47.91%	46.34%	47.25%	47.52%	48.85%	46.05%	46.10%	47.19%	47.12%
Ameren Corporation	AEE	47.52%	46.32%	47.66%	47.13%	45.91%	46.54%	46.76%	46.87%	46.91%	46.84%
American Electric Power Company, Inc.	AEP	50.41%	50.59%	50.67%	50.25%	50.09%	51.20%	50.38%	50.60%	50.40%	50.52%
Avista Corporation	AVA	39.33%	44.02%	44.26%	44.78%	44.20%	43.68%	43.90%	44.91%	43.31%	43.63%
CMS Energy Corporation	CMS	48.33%	49.77%	50.08%	48.42%	48.18%	46.24%	47.35%	49.59%	48.96%	48.50%
Consolidated Edison, Inc.	ED	52.88%	52.40%	52.48%	51.77%	50.15%	50.92%	51.25%	52.03%	51.94%	51.74%
DTE Energy Company	DTE	51.17%	54.35%	52.73%	49.96%	50.60%	51.24%	51.31%	49.04%	51.76%	51.30%
Duke Energy Corporation	DUK	46.73%	46.98%	46.79%	46.54%	47.11%	45.52%	46.86%	45.65%	46.83%	46.52%
Entergy Corporation	ETR	52.20%	52.39%	52.42%	51.17%	50.79%	51.81%	51.19%	49.89%	51.79%	51.48%
Evergy, Inc	EVRG	39.70%	40.79%	39.89%	39.86%	39.72%	39.49%	41.84%	40.44%	39.99%	40.22%
Eversource Energy	ES	46.64%	46.91%	47.56%	46.90%	50.16%	50.30%	45.47%	46.40%	47.63%	47.54%
Hawaiian Electric Industries, Inc.	HE	42.72%	43.33%	43.25%	42.25%	41.57%	41.83%	41.94%	42.02%	42.62%	42.36%
IDACORP, Inc.	IDA	45.96%	48.75%	44.82%	44.86%	44.80%	45.42%	45.64%	45.75%	45.84%	45.75%
NextEra Energy, Inc.	NEE	38.18%	37.67%	41.94%	44.73%	43.85%	38.78%	35.97%	35.63%	41.27%	39.59%
NorthWestern Corporation	NWE	51.74%	51.39%	52.22%	52.41%	52.20%	51.93%	51.26%	52.12%	51.99%	51.91%
OGE Energy Corp.	OGE	47.22%	46.91%	44.72%	44.85%	45.04%	46.53%	44.62%	46.80%	45.75%	45.84%
Otter Tail Corporation	OTTR	47.28%	47.16%	49.15%	48.88%	44.57%	46.25%	46.10%	46.42%	47.41%	46.97%
Pinnacle West Capital Corporation	PNW	48.42%	48.11%	46.34%	47.20%	45.75%	45.59%	45.52%	45.64%	47.17%	46.57%
Portland General Electric Company	POR	52.15%	51.67%	49.91%	50.15%	48.22%	48.44%	49.40%	49.81%	50.42%	49.97%
Public Service Enterprise Group Incorporated	PEG	46.17%	46.54%	46.23%	45.28%	45.35%	45.69%	44.86%	45.76%	45.91%	45.74%
Southern Company	SO	45.07%	45.55%	45.21%	47.04%	47.38%	46.79%	45.68%	45.54%	46.05%	46.03%
WEC Energy Group, Inc.	WEC	43.48%	44.10%	44.67%	44.49%	44.14%	43.22%	44.19%	46.47%	44.18%	44.35%
Xcel Energy Inc.	XEL	45.99%	47.11%	45.46%	45.78%	46.02%	45.30%	45.49%	45.78%	46.07%	45.86%
Mean		46.65%	47.23%	46.92%	46.80%	46.44%	46.33%	45.98%	46.26%	46.81%	46.57%
Median		46.82%	47.04%	46.34%	46.97%	45.97%	46.24%	45.66%	46.25%	46.87%	46.55%

Operating Company Capital Structure

		% Long-Term Debt									
Operating Company	Parent	2020Q3	2020Q2	2020Q1	2019Q4	2019Q3	2019Q2	2019Q1	2018Q4	5Q Average	8Q Average
Ameren Illinois Company	AEE	NA	43.52%	45.34%	46.63%	45.15%	45.56%	45.95%	46.73%	45.16%	45.55%
Union Electric Company	AEE	47.52%	49.12%	49.98%	47.64%	46.67%	47.52%	47.56%	47.00%	48.19%	47.88%
AEP Texas Inc.	AEP	57.94%	54.96%	55.84%	56.23%	53.03%	53.68%	52.46%	54.62%	55.60%	54.85%
Appalachian Power Company	AEP	52.90%	53.35%	50.84%	51.26%	51.26%	51.81%	52.23%	50.49%	51.92%	51.77%
Indiana Michigan Power Company	AEP	51.65%	52.17%	52.58%	53.26%	53.49%	54.17%	54.57%	55.38%	52.63%	53.41%
Kentucky Power Company	AEP	55.12%	55.43%	55.40%	52.66%	53.06%	53.50%	53.58%	54.28%	54.33%	54.13%
Kingsport Power Company	AEP	44.58%	45.02%	44.96%	45.38%	45.76%	49.82%	48.46%	49.21%	45.14%	46.65%
Ohio Power Company	AEP	47.90%	48.25%	48.82%	45.50%	46.37%	47.08%	41.14%	42.20%	47.37%	45.91%
Public Service Company of Oklahoma	AEP	48.05%	49.43%	50.49%	50.31%	50.11%	51.98%	52.81%	50.84%	49.68%	50.50%
Southwestern Electric Power Company	AEP	49.43%	50.29%	51.03%	51.20%	51.37%	52.55%	52.41%	53.03%	50.67%	51.41%
Wheeling Power Company	AEP	46.14%	46.45%	46.11%	46.49%	46.34%	46.17%	45.73%	45.38%	46.30%	46.10%
ALLETE (Minnesota Power)	ALE	45.70%	44.20%	41.68%	40.41%	40.67%	39.06%	39.13%	38.61%	42.53%	41.18%
Superior Water, Light and Power Company	ALE	41.06%	41.32%	40.86%	41.92%	41.97%	41.62%	41.81%	43.14%	41.42%	41.71%
Alaska Electric Light and Power Company	AVA	39.33%	39.38%	39.66%	40.38%	38.72%	38.76%	38.98%	39.71%	39.49%	39.37%
Avista Corporation	AVA	NA	48.65%	48.85%	49.17%	49.67%	48.60%	48.82%	50.11%	49.09%	49.13%
Consumers Energy Company	CMS	48.33%	49.77%	50.08%	48.42%	48.18%	46.24%	47.35%	49.59%	48.96%	48.50%
DTE Electric Company	DTE	51.17%	54.35%	52.73%	49.96%	50.60%	51.24%	51.31%	49.04%	51.76%	51.30%
Duke Energy Carolinas, LLC	DUK	48.07%	48.44%	49.74%	47.89%	48.20%	47.06%	47.68%	48.22%	48.47%	48.16%
Duke Energy Florida, LLC	DUK	47.90%	48.88%	48.70%	50.09%	47.18%	48.45%	49.44%	49.96%	48.55%	48.83%
Duke Energy Indiana, LLC	DUK	46.92%	49.88%	49.78%	47.16%	48.48%	45.17%	45.71%	46.74%	48.44%	47.48%
Duke Energy Kentucky, Inc.	DUK	50.72%	48.65%	49.93%	50.63%	54.56%	46.96%	47.19%	48.05%	50.90%	49.59%
Duke Energy Ohio, Inc.	DUK	37.84%	38.27%	34.39%	34.78%	35.10%	35.55%	40.71%	31.91%	36.08%	36.07%
Duke Energy Progress, LLC	DUK	48.90%	47.77%	48.18%	48.71%	49.14%	49.91%	50.40%	49.00%	48.54%	49.00%
Consolidated Edison Company of New York, Inc	ED	52.83%	53.36%	53.77%	51.59%	50.71%	51.08%	51.70%	52.48%	52.45%	52.19%
Orange and Rockland Utilities, Inc.	ED	52.94%	51.43%	51.18%	51.95%	49.60%	50.75%	50.79%	51.59%	51.42%	51.28%
Rockland Electric Company	ED	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Connecticut Light and Power Company	ES	41.90%	43.15%	43.77%	44.03%	45.20%	43.94%	41.16%	43.15%	43.61%	43.29%
Public Service Company of New Hampshire	ES	52.40%	51.01%	51.74%	52.23%	59.36%	59.98%	51.62%	52.08%	53.35%	53.80%
NSTAR Electric Company	ES	45.61%	46.57%	47.15%	44.43%	45.92%	46.97%	43.64%	43.98%	45.94%	45.53%
Entergy Arkansas, LLC	ETR	55.58%	52.07%	52.54%	52.10%	52.28%	53.51%	52.96%	50.58%	52.91%	52.70%
Entergy Louisiana, LLC	ETR	51.77%	53.38%	54.00%	52.53%	52.87%	53.68%	54.21%	52.63%	52.91%	53.13%
Entergy Mississippi, LLC	ETR	52.09%	52.91%	51.08%	51.40%	51.65%	55.07%	50.59%	50.89%	51.82%	51.96%
Entergy New Orleans, LLC	ETR	54.26%	55.18%	55.42%	50.74%	46.31%	47.60%	48.31%	48.81%	52.38%	50.83%
Entergy Texas, Inc.	ETR	47.32%	48.41%	49.03%	49.08%	50.84%	49.21%	49.87%	46.54%	48.94%	48.79%
Evergy Kansas South, Inc.	EVRG	17.45%	17.82%	17.97%	18.04%	18.16%	18.51%	24.87%	25.03%	17.89%	19.73%
Evergy Metro, Inc.	EVRG	51.23%	52.88%	50.03%	49.69%	49.57%	50.38%	53.96%	50.51%	50.68%	51.03%
Evergy Missouri West, Inc.	EVRG	47.09%	48.26%	49.48%	49.66%	48.82%	48.26%	47.32%	45.29%	48.66%	48.02%
Westar Energy (KPL)	EVRG	43.03%	44.19%	42.08%	42.03%	42.34%	40.82%	41.20%	40.92%	42.73%	42.07%
Hawaii Electric Light Company, Inc.	HE	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Hawaiian Electric Company, Inc.	HE	42.72%	43.33%	43.25%	42.25%	41.57%	41.83%	41.94%	42.02%	42.62%	42.36%
Maui Electric Company, Limited	HE	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Idaho Power Company	IDA	45.96%	48.75%	44.82%	44.86%	44.80%	45.42%	45.64%	45.75%	45.84%	45.75%
Interstate Power and Light Company	LNT	46.60%	48.30%	47.32%	48.28%	48.44%	46.70%	45.13%	44.90%	47.79%	46.96%
Wisconsin Power and Light Company	LNT	47.22%	47.53%	45.36%	46.22%	46.60%	50.99%	46.97%	47.31%	46.59%	47.28%
Florida Power & Light Company	NEE	40.01%	36.84%	39.86%	39.76%	40.22%	38.70%	35.97%	35.63%	39.34%	38.37%
Gulf Power Company	NEE	36.34%	38.49%	44.03%	49.70%	47.48%	38.85%	NA	NA	43.21%	42.48%
NorthWestern Corporation	NWE	51.74%	51.39%	52.22%	52.41%	52.20%	51.93%	51.26%	52.12%	51.99%	51.91%
Oklahoma Gas and Electric Company	OGE	47.22%	46.91%	44.72%	44.85%	45.04%	46.53%	44.62%	46.80%	45.75%	45.84%
Otter Tail Power Company	OTTR	47.28%	47.16%	49.15%	48.88%	44.57%	46.25%	46.10%	46.42%	47.41%	46.97%
Public Service Electric and Gas Company	PEG	46.17%	46.54%	46.23%	45.28%	45.35%	45.69%	44.86%	45.76%	45.91%	45.74%
Arizona Public Service Company	PNW	48.42%	48.11%	46.34%	47.20%	45.75%	45.59%	45.52%	45.64%	47.17%	46.57%
Portland General Electric Company	POR	52.15%	51.67%	49.91%	50.15%	48.22%	48.44%	49.40%	49.81%	50.42%	49.97%
Alabama Power Company	SO	47.31%	46.24%	46.14%	48.10%	47.74%	46.63%	46.93%	51.26%	47.11%	47.55%
Georgia Power Company	SO	43.41%	45.41%	44.30%	43.88%	44.62%	43.61%	43.57%	40.98%	44.32%	43.72%
Gulf Power Company	SO	NA	NA	NA	NA	NA	NA	41.94%	40.27%	NA	41.11%
Mississippi Power Company	SO	44.47%	45.01%	45.20%	49.16%	49.77%	50.13%	50.27%	49.65%	46.72%	47.96%
Upper Michigan Energy Resources Corporation	WEC	45.90%	46.48%	47.19%	44.55%	43.91%	45.55%	47.46%	52.99%	45.61%	46.75%
Wisconsin Electric Power Company	WEC	41.84%	42.61%	43.11%	43.52%	42.88%	43.15%	44.00%	43.75%	42.79%	43.11%
Wisconsin Public Service Corporation	WEC	42.71%	43.22%	43.71%	45.39%	45.63%	40.96%	41.12%	42.67%	44.13%	43.18%
Northern States Power Company - MN	XEL	47.80%	49.87%	47.45%	47.80%	48.21%	46.34%	46.36%	47.19%	48.22%	47.63%
Northern States Power Company - WI	XEL	46.87%	47.39%	45.10%	45.77%	46.44%	46.51%	46.41%	46.40%	46.32%	46.36%
Public Service Company of Colorado	XEL	43.44%	45.40%	43.42%	43.68%	43.65%	42.47%	43.32%	43.69%	43.92%	43.63%
Southwestern Public Service Company	XEL	45.85%	45.78%	45.87%	45.86%	45.79%	45.86%	45.87%	45.83%	45.83%	45.84%
Mean		46.91%	47.30%	47.12%	47.00%	46.91%	46.79%	46.65%	46.69%	47.05%	46.83%
Median		47.28%	48.25%	47.45%	47.89%	47.18%	46.96%	46.97%	47.00%	47.41%	47.38%

Proxy Group Capital Structure

Company	Ticker	% Preferred Equity 2020Q3	2020Q2	2020Q1	2019Q4	2019Q3	2019Q2	2019Q1	2018Q4	5Q Average	8Q Average
ALLETE, Inc.	ALE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Alliant Energy Corporation	LNT	1.36%	1.41%	1.47%	1.49%	1.50%	1.59%	1.64%	1.70%	1.44%	1.52%
Ameren Corporation	AEE	0.88%	0.83%	0.85%	0.88%	0.91%	0.92%	0.92%	0.94%	0.87%	0.89%
American Electric Power Company, Inc.	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Avista Corporation	AVA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CMS Energy Corporation	CMS	0.23%	0.22%	0.23%	0.25%	0.25%	0.26%	0.27%	0.27%	0.23%	0.25%
Consolidated Edison, Inc.	ED	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
DTE Energy Company	DTE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Corporation	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Entergy Corporation	ETR	0.17%	0.18%	0.18%	0.20%	0.21%	0.00%	0.00%	0.00%	0.19%	0.12%
Evergy, Inc	EVRG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Eversource Energy	ES	0.64%	0.65%	0.66%	0.67%	0.69%	0.71%	0.74%	0.72%	0.66%	0.69%
Hawaiian Electric Industries, Inc.	HE	0.61%	0.61%	0.62%	0.63%	0.65%	0.66%	0.66%	0.66%	0.62%	0.64%
IDACORP, Inc.	IDA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NextEra Energy, Inc.	NEE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NorthWestern Corporation	NWE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
OGE Energy Corp.	OGE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Otter Tail Corporation	OTTR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Pinnacle West Capital Corporation	PNW	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Portland General Electric Company	POR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Public Service Enterprise Group Incorporated	PEG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Southern Company	SO	0.51%	0.54%	0.54%	0.56%	0.55%	0.58%	0.44%	0.47%	0.54%	0.52%
WEC Energy Group, Inc.	WEC	0.15%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%
Xcel Energy Inc.	XEL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mean		0.19%	0.19%	0.20%	0.20%	0.20%	0.20%	0.20%	0.21%	0.20%	0.20%
Median		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Operating Company Capital Structure

		% Long-Term Debt									
Operating Company	Parent	2020Q3	2020Q2	2020Q1	2019Q4	2019Q3	2019Q2	2019Q1	2018Q4	5Q Average	8Q Average
Ameren Illinois Company	AEE	NA	0.74%	0.77%	0.80%	0.84%	0.85%	0.86%	0.87%	0.79%	0.82%
Union Electric Company	AEE	0.88%	0.91%	0.93%	0.97%	0.97%	0.99%	0.99%	1.01%	0.94%	0.96%
AEP Texas Inc.	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Appalachian Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Indiana Michigan Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Kentucky Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Kingsport Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Ohio Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Public Service Company of Oklahoma	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Southwestern Electric Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Wheeling Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
ALLETE (Minnesota Power)	ALE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Superior Water, Light and Power Company	ALE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Alaska Electric Light and Power Company	AVA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Avista Corporation	AVA	NA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Consumers Energy Company	CMS	0.23%	0.22%	0.23%	0.25%	0.25%	0.26%	0.27%	0.27%	0.23%	0.25%
DTE Electric Company	DTE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Carolinas, LLC	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Florida, LLC	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Indiana, LLC	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Kentucky, Inc.	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Ohio, Inc.	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Duke Energy Progress, LLC	DUK	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Consolidated Edison Company of New York, Inc	ED	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Orange and Rockland Utilities, Inc.	ED	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Rockland Electric Company	ED	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Connecticut Light and Power Company	ES	1.37%	1.42%	1.44%	1.44%	1.48%	1.53%	1.58%	1.53%	1.43%	1.47%
Public Service Company of New Hampshire	ES	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NSTAR Electric Company	ES	0.54%	0.55%	0.55%	0.57%	0.59%	0.60%	0.63%	0.64%	0.56%	0.58%
Entergy Arkansas, LLC	ETR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Entergy Louisiana, LLC	ETR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Entergy Mississippi, LLC	ETR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Entergy New Orleans, LLC	ETR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Entergy Texas, Inc.	ETR	0.86%	0.88%	0.89%	0.99%	1.03%	0.00%	0.00%	0.00%	0.93%	0.58%
Evergy Kansas South, Inc.	EVRG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Evergy Metro, Inc.	EVRG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Evergy Missouri West, Inc.	EVRG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Westar Energy (KPL)	EVRG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Hawaii Electric Light Company, Inc.	HE	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Hawaiian Electric Company, Inc.	HE	0.61%	0.61%	0.62%	0.63%	0.65%	0.66%	0.66%	0.66%	0.62%	0.64%
Maui Electric Company, Limited	HE	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Idaho Power Company	IDA	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Interstate Power and Light Company	LNT	2.72%	2.82%	2.93%	2.98%	2.99%	3.18%	3.28%	3.41%	2.89%	3.04%
Wisconsin Power and Light Company	LNT	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Florida Power & Light Company	NEE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Gulf Power Company	NEE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	NA	NA	0.00%	0.00%
NorthWestern Corporation	NWE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Oklahoma Gas and Electric Company	OGE	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Otter Tail Power Company	OTTR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Public Service Electric and Gas Company	PEG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Arizona Public Service Company	PNW	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Portland General Electric Company	POR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Alabama Power Company	SO	1.54%	1.61%	1.62%	1.67%	1.66%	1.74%	1.75%	1.87%	1.62%	1.68%
Georgia Power Company	SO	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Gulf Power Company	SO	NA	NA	NA	NA	NA	NA	0.00%	0.00%	NA	0.00%
Mississippi Power Company	SO	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Upper Michigan Energy Resources Corporation	WEC	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Wisconsin Electric Power Company	WEC	0.46%	0.47%	0.47%	0.48%	0.48%	0.48%	0.49%	0.49%	0.47%	0.48%
Wisconsin Public Service Corporation	WEC	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Northern States Power Company - MN	XEL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Northern States Power Company - WI	XEL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Public Service Company of Colorado	XEL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Southwestern Public Service Company	XEL	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Mean		0.16%	0.17%	0.18%	0.18%	0.19%	0.17%	0.18%	0.18%	0.18%	0.17%
Median		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

UNITIL ENERGY SYSTEMS, INC.

DIRECT TESTIMONY OF

NED W. ALLIS

EXHIBIT NWA-1

New Hampshire Public Utilities Commission

Docket No. DE 21-030

TABLE OF CONTENTS

Attachments

Exhibit NWA-2 – Qualification Statement

Exhibit NWA-3 – Depreciation Study

Exhibit NWA-4 – Comparison of Current Annual Depreciation Expense vs. Proposed Annual Depreciation Expense

I. INTRODUCTION

Q. Please state your name and address.

A. My name is Ned W. Allis. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania 17011.

Q. Are you associated with any firm?

A. Yes. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming").

Q. How long have you been associated with Gannett Fleming?

A. I have been associated with the firm since 2006.

Q. What is your position with the firm?

A. I am Vice President.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of Unitil Energy Systems, Inc. ("UES" or the "Company").

Q. Please state your qualifications.

A. I have 14 years of experience within the field of depreciation, which includes providing expert testimony in more than 40 cases before 14 regulatory commissions. I have also worked on numerous depreciation studies for which I did not submit testimony, including assisting other expert witnesses from Gannett

Fleming in additional U.S. jurisdictions and two Canadian provinces. Exhibit NWA-2 to my testimony provides my qualifications, including leadership in the Society of Depreciation Professionals (the "Society") and participation as a faculty member for depreciation training conducted by the Society.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the depreciation study performed for UES attached hereto as Exhibit NWA-3. The Depreciation Study sets forth the calculated annual depreciation accrual rates by account as of December 31, 2020 for all electric plant.

Q. Please summarize the impact in depreciation rates based on the Depreciation Study.

A. The table below sets forth a comparison of the current depreciation rates and resultant expense of the proposed depreciation rates by function as of December 31, 2020.

Table 1: Comparison of Current and Proposed Depreciation Rates as of December 31, 2020

	Current		Proposed	
Function	Rates (pct)	Pro Forma Expense	Rates (pct)	Expense
Production	6.67	$3,774	18.66	$10,559
Distribution	3.59	12,654,504	3.39	11,945,637
General	3.23	936,655	2.62	760,082
General Reserve Adj.		-		86,569

Total	3.57	13,594,933	3.36	12,802,847

Q. Please explain the major factors that caused the change in depreciation rates.

A. The major factors that cause changes in depreciation rates are the estimated service lives, estimated net salvage, and the recovery of the theoretical reserve imbalances that result from the study. For many accounts, the recommended service life estimates are longer than those used for the current depreciation rates. While this is partially offset by more negative net salvage estimates for many accounts, the overall result is a net reduction in depreciation expense.

In the Company's previous depreciation study, the whole life technique was used, which does not automatically address any difference between the book reserve and calculated (or "theoretical") reserve. For the current study, the remaining life technique was used, which effectively recovers any such differences over the remaining lives of the Company's assets. The method of recovering any differences between the book and theoretical reserve will also impact the resultant depreciation expense, and the use of the remaining life technique in the depreciation study also impacts the recommended depreciation rates.

Q. Are the recommended depreciation accrual rates presented in your study reasonable and applicable to the plant in service as of December 31, 2020?

A. Yes, they are. Based on the Depreciation Study, I am recommending depreciation rates using the December 31, 2020 plant and reserve balances for approval.

III. DEPRECIATION STUDY

Q. Please define the concept of depreciation.

A. Depreciation refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, obsolescence, changes in the art, changes in demand and the requirements of public authorities.

Q. Please identify the Depreciation Study you performed for UES.

A. The study is a report entitled, "2020 Depreciation Study - Calculated Annual Depreciation Accruals Related to Electric Plant as of December 31, 2020." This report sets forth the results of my depreciation study for UES. The study was prepared and the analyses that underlie the study were conducted under my direction and supervision.

Q. Is Exhibit NWA-3 a true and accurate copy of your Depreciation Study?

A. Yes.

Q. Does Exhibit NWA-3 accurately portray the results of your Depreciation Study as of December 31, 2020?

A. Yes.

Q. What was the purpose of the Depreciation Study?

A. The purpose of the Depreciation Study was to estimate the annual depreciation accruals related to electric plant in service for financial and ratemaking purposes and determine appropriate service lives and net salvage percentages for each plant account.

Q. Are the methods and procedures of the Depreciation Study consistent with industry practices?

A. Yes, the methods and procedures of the study are generally in accordance with industry standards. Both the existing rates and the proposed rates determined in the Depreciation Study are based on the average service life procedure. However, the proposed rates are determined based on the more common remaining life method while existing rates are based on the whole life method.

Q. What are the most common depreciation methods?

A. The calculation of depreciation requires the selection of a depreciation method, which includes the selection of a procedure and technique (or basis) for calculating depreciation rates. The recommended depreciation rates in the Depreciation Study are based on the straight-line method, average service life – broad group procedure and remaining life technique, which is the most commonly used depreciation method for public utility depreciation. The straight-line method and average service life – broad group procedure was used in the previous depreciation study for UES. However, the use of the remaining life technique is a change from the previous depreciation study for the Company, in which the whole life technique was used.

For the whole life technique, depreciation is calculated based on the basis of the full service life, or whole life, estimated for a group of assets. For example, if the service life estimate for an asset that costs $100 is 10 years, and no net salvage is expected, then the annual depreciation rate would be 10% (or (1-0%)/10). Issues can arise with the whole life technique if service life estimates change or if the real-world experience of the group does not perfectly match the service life and net salvage estimates used to develop depreciation rates. Using the same example, if after five years of the asset's life the accumulated depreciation was $60, then applying a 10% whole life depreciation rate for each of the remaining five years of the asset's life would result in a total recovery through depreciation of $110 (the $60 in accumulated depreciation plus $10 per year for five years). As a result, the whole life technique would, without an adjustment, result in the recovery of the incorrect amount of depreciation expense. Such situations can, and do, arise regularly because depreciation is, by nature, a forecast of the future for thousands of individual assets.

The remaining life technique addresses the issue described in the previous paragraph by taking a prospective approach of allocating unrecovered costs over the expected time the related assets will remain in service. Rather than calculating depreciation based on the whole service life, the remaining life technique allocates the amount remaining to be recovered (which is the original cost for a depreciable group less net salvage less accumulated depreciation) over its estimated remaining life. As a result, the remaining life technique ensures that the full service value (original cost less net salvage) will be recovered through depreciation expense – no more or no less. In part for this reason, the remaining life technique is used in the vast majority of U.S. regulatory jurisdictions and for most depreciation studies. Its use is recommended in the Depreciation Study.

Q. Why is the remaining life technique superior to the whole life method?

A. A simple example will explain why the remaining life methodology is superior. Assume that there is a single asset with a cost of $100, an estimated service life of 10 years and no net salvage. The depreciation rate would be 10% and the annual depreciation expense would be $10. After five years, a new depreciation study is performed and the service life is determined to be 15 years. Using the whole life technique, the depreciation rate would be changed to 6.67% and the annual depreciation expense would be $6.67. If the whole life technique were used, then over the full 15-year service life, a total of $116.70 would be recovered through depreciation expense ($10 per year for the first five years and $6.67 per year for the final ten years). However, this means that too much depreciation expense is recovered over the service life, as more than the $100 cost of the asset is recovered through depreciation expense.

When using the remaining life technique, the depreciation expense would be the same $10 per year for the first five years. However, when the updated depreciation study is performed after year five and the 15-year life is determined, the depreciation rate is calculated to incorporate the amount of depreciation recovered to date. That is, the remaining life technique recognizes that $50 of the $100 has been recovered allocates the remaining $50 (i.e., $100 - $50) in future depreciation expense over the 10 year remaining life, for a depreciation rate of 5% and an annual depreciation expense of $5. Over the 15-year service life of the asset, $100 is recovered through depreciation expense ($10 per year for the first five years and $5 per year for the last ten years). Thus, the remaining life technique corrects the issue that arises from the use of the whole life technique, for which too much depreciation expense would be recovered.

Q. Please describe the contents of Exhibit NWA-3.

A. My report is presented in nine parts. Part I, Introduction, describes the scope and basis for the Depreciation Study. Part II, Estimation of Survivor Curves, includes descriptions of the methodology of estimating survivor curves. Parts III and IV set forth the analysis for determining life and net salvage estimates. Part V, Calculation of Annual and Accrued Depreciation, includes the concepts of depreciation and amortization using the remaining life method. Part VI, Results of Study, presents a description of the results and a summary of the depreciation calculations. Parts VII, VIII and IX include graphs and tables that relate to the service life and net salvage analyses, and the detailed depreciation calculations. The table on pages VI-4 and VI-5 of Exhibit NWA-3 presents the estimated survivor curve, the net salvage percent, the original cost as of December 31, 2020, the book depreciation reserve, and the calculated annual depreciation accrual and rate for the account or subaccount. The section beginning on page VII-2 presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page VIII-2 presents the results of the net salvage analysis. The section beginning on page IX-2 presents the depreciation calculations related to surviving original cost as of December 31, 2020.

Q. Please explain how you performed your Depreciation Study.

A. I used the straight line remaining life method of depreciation, with the average service life procedure. The annual depreciation is based on a method of depreciation accounting that seeks to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of the unit, or group of assets, in a systematic and rational manner.

Q. How did you determine the recommended annual depreciation accrual rates?

A. I did this in two phases. In the first phase, I estimated the service life and net salvage characteristics for each depreciable group, that is, the plant accounts or subaccounts identified as having similar characteristics. In the second phase, I calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

Q. Please describe the first phase of the Depreciation Study, in which you estimated the service life and net salvage characteristics for the depreciable group.

A. The service life and net salvage analyses consisted of compiling historic data from records related to UES's plant; analyzing these data to obtain historic trends of survivor and net salvage characteristics; obtaining supplementary information from UES management personnel and operating personnel concerning practices and plans as they relate to plant operations; and interpreting the above data based on my experience and consideration of estimates used by other electric utilities to form judgments of average service life and net salvage characteristics.

Q. What historical data did you rely on to estimate service life characteristics?

A. I analyzed accounting entries for the Company relating to plant additions, transfers, and retirements recorded through 2020. The records of the Company also included transactional data and surviving dollar value by year installed for each plant account as of December 31, 2020. For the current study, aged data – i.e., data that incorporates the actual age of retirements – were available from 2010 through 2020. Because many of the assets studied have historically had lives that, on average, spanned many decades, the aged data was supplemented with statistically aged data through 2009 based on the unaged data analyzed in previous studies. This allowed for a longer period of data to be included in the study. Actuarial analyses were performed on both the full period of data available – i.e., both aged and statistically aged – as well as for the period for which only aged data was available.

Q. What method did you use to analyze this service life data?

A. I used the retirement rate method for all accounts. This is the most appropriate method when aged retirement data are available, because this method determines the average rates of retirement actually experienced by the Company during the period of time covered by the study.

Q. Please explain how you used the retirement rate method to analyze UES's service life data.

A. I applied the retirement rate method to each group of property in the Depreciation Study. For each property group, I used the retirement rate method to form a life table, which, when plotted, shows an original survivor curve for that property group. The original survivor curve represents the average survivor pattern experienced by multiple vintage groups during the experienced band studied. The survivor patterns alone do not necessarily describe the life characteristics of the property group; therefore, interpretation of the original survivor curves is required in order to use them as valid considerations in estimating service life. The Iowa-type Survivor Curves were used to perform these interpretations.

Q. What is an "Iowa-type Survivor Curve" and how did you use such curves to estimate the service life characteristics for the property group?

A. Iowa-type Survivor Curves are a widely used group of generalized survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies have been retired.

Iowa-type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Depreciation Study used Iowa curves and truncated original curves to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements. The estimated survivor curve designations for the depreciable property group indicate the average service life, the family within the Iowa system to which the property group belongs, and the relative height of the mode. For example, the Iowa 45-R3 indicates an average service life of 45 years; a right-moded, or R type curve (the mode occurs after average life for right-moded curves); and a medium height, 3, for the mode (possible modes for R type curves range from 0.5 to 5).

Q. Did you physically observe UES's plant and equipment as part of the Depreciation Study?

A. No. My typical practice is to perform physical site visits for depreciation studies. However, due to restrictions in place related to the COVID-19 pandemic, I have not been able to perform a physical site visit for this study. In lieu of a physical site visit, the Company provided virtual site visits of certain facilities. In addition, I conducted meetings with the Company's operating and engineering personnel to develop an understanding of the Company's assets and future plans. Accordingly, despite the COVID-19 related restrictions, I was able to obtain the information needed for the study through the combination of virtual site visits, meetings with

Company personnel and my experience with other depreciation studies allowed.

Q. How did your experience in development of other depreciation studies affect your work in this case for UES?

A. Since I customarily conduct field reviews for my depreciation studies, I have had the opportunity to visit similar facilities and meet with management and operations personnel at many other companies. The knowledge I have accumulated from those visits and meetings provides me with useful information to draw upon to confirm or challenge my numerical analyses concerning asset condition and remaining life estimates.

Q. Are the factors considered in your estimates of service life and net salvage percentages presented in Exhibit NWA-3?

A. Yes. Discussions of the factors considered in the estimation of service lives and net salvage percentages are presented in Parts III and IV of the study.

Q. Please describe the concept of "net salvage".

A. Net salvage is a component of the service value of capital assets that is recovered through depreciation rates. The service value of an asset is its original cost less its net salvage. Net salvage is the gross salvage value received for the asset upon retirement less the cost to retire the asset. When the cost to retire the asset exceeds the gross salvage value, the result is negative net salvage.

Because depreciation expense is the loss in service value of an asset during a defined period (e.g., one year), it must include a ratable portion of both the original cost of the asset and the net salvage. That is, the net salvage related to an asset should be incorporated in the cost of service during the same period as its original cost, so customers receiving service from the asset pay rates that include a portion of both elements of the asset's service value, the original cost and the net salvage value. For example, the full service value of a $1,000 pole may also include $550 of cost of removal and $50 gross salvage, for a total service value of $1,500.

Q. Please describe how you estimated net salvage percentages.

A. I estimated the net salvage percentages by incorporating the Company's actual historical data through 2020 and considered industry experience of net salvage estimates for other electric companies. The net salvage percentages in the Depreciation Study are based on a combination of statistical analyses and informed judgment. The statistical analyses consider the cost of removal and gross salvage ratios to the associated retirements during the 26-year period for which data were available for UES. Trends of these data are also measured based on three-year moving averages and the most recent five-year indications.

Q. Please describe the second phase of the process that you used in the Depreciation Study in which you calculated composite remaining lives and annual depreciation accrual rates.

A. After I estimated the service life and net salvage characteristics for the depreciable property group, I calculated the annual depreciation accrual rates for the group based on the straight line remaining life method, using remaining lives weighted consistent with the average service life procedure. The calculation of annual depreciation accrual rates was developed as of December 31, 2020.

Q. Please describe the straight line remaining life method of depreciation.

A. The straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to the year of remaining service life. This method recovers the variance between the actual book reserve and the theoretical book reserve over the remaining life of each asset class.

Q. Please describe the average service life procedure for calculating remaining life accrual rates.

A. The average service life procedure defines the group or account for which the remaining life annual accrual is determined. For this procedure, the annual accrual rate is determined for the entire group or account based on its average remaining life and the rate is then applied to the surviving balance of the group's cost. The average remaining life of the group is calculated by first dividing the future book accruals (original cost less allocated book reserve less future net salvage) by the average remaining life for the vintage. The average remaining life for the vintage is derived from the area under the survivor curve between the attained age of the vintage and the maximum age. The sum of the future book accruals is then divided by the sum of the annual accruals to determine the average remaining life of the entire group for use in calculating the annual depreciation accrual rate.

Q. Please describe amortization accounting in contrast to depreciation accounting.

A. Amortization accounting is recommended for accounts with a large number of units, but small asset values. In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. However, depreciation accounting is difficult for these types of assets because depreciation accounting requires periodic inventories to properly reflect plant in service. Consequently, amortization accounting is used for these types of assets, such that retirements are recorded when a vintage is fully amortized rather than as the units are removed from service. That is, there is no dispersion of retirements in amortization accounting. All units are retired when the age of the vintage reaches the amortization period. The plant account or group of assets is assigned a fixed period that represents an anticipated life during which the asset will provide service. For example, in amortization accounting, assets that have a 15-year amortization period will be fully recovered after 15 years of service and taken off the company's books at that time, but not necessarily removed from service. In contrast, assets that are taken out of service before 15 years remain on the books until the amortization period for that vintage has expired.

Q. Is amortization accounting being utilized for certain plant accounts?

A. Yes. However, amortization accounting is only appropriate for certain General Plant accounts. The General Plant accounts are 391.01, 393.00, 394.00, 395.00, 397.00 and 398.00. These accounts represent less than three percent of UES's depreciable plant.

Q. Have you made additional recommendations for these amortization accounts?

A. Yes. In order to achieve a more stable accrual rate for these accounts in the future, I have recommended a five-year amortization to adjust the reserve for these amortization accounts. This approach will achieve consistent amortization rates for existing assets as well as future assets.

Q. Please provide an example to illustrate the development of the annual depreciation accrual rate for a particular group of property in your Depreciation Study.

A. I will use Account 362.00, Station Equipment, as an example because it is one of the largest depreciable groups. The retirement rate method was used to analyze the survivor characteristics of this property group. Aged plant accounting data were compiled from 2010 through 2020 and statistically aged data were compiled from 1995 through 2009. The life tables for the 1995-2020 experience band and 2010-2020 experience bands are presented on pages VII-9 through VII-14 of Exhibit NWA-3. The life tables display the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page VII-9 shows $4,964 retired during age interval 0.5-1.5 with $42,384,257 exposed to retirement at the beginning of the interval. Consequently, the retirement ratio is 0.0001 ($4,964/$42,384,257) and the survivor ratio is 0.9999 (1-0.0001). The percent surviving at age 0.5 of 100.00 percent is multiplied by the survivor ratio of 0.9999 to derive the percent surviving at age 1.5 of 99.99 percent. This process continues for the remaining age intervals for which plant was exposed to retirement during the period 1995-2020. The resultant life tables, or original survivor curves, are plotted along with the estimated smooth survivor curve, the 49-R1.5 on page VII-8.

The experienced net salvage percentages are presented on page VIII-4 and VIII-5 of Exhibit NWA-3. The percentages are based on the result of annual gross salvage minus the cost to remove plant assets as compared to the original cost of plant retired during the period 1995 through 2020. The twenty-six-year period experienced negative $1,997,460 ($129,984 - $2,127,444) in net salvage for $3,827,889 plant retired. The result is net salvage of negative 52 percent ($1,997,460/$3,827,889). The most recent five-year average is negative 51 percent. Therefore, based on the statistics for this account, the three-year rolling averages, the trend in recent years, as well as the estimates of other electric companies, the recommended net salvage for station equipment is negative 40 percent.

The calculation of the annual depreciation related to original cost of Account 362.00, Station Equipment as of December 31, 2020, is presented on pages IX-4 through IX-6 of Exhibit NWA-3. The calculation is based on the 49-R1.5

survivor curve, the negative net salvage of 40 percent, the attained age, and the allocated book reserve. The tabulation sets forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life and annual accrual. These totals are brought forward to the table on page VI-4.

Q. Please compare the proposed depreciation expense to the current pro forma depreciation expense as of December 31, 2020.

A. Exhibit NWA-4 sets forth the proposed versus current depreciation expense as of December 31, 2020 for the Company. The overall change reflected in the UES Depreciation Study is a decrease in annual depreciation expense at this date of $792,086.

Q. Have you established any special amortizations within the study?

A. Yes. I have established a 5-year amortization for certain General Plant accounts in order to stabilize the current and future rates for these assets as well as ensure full recovery of the service value of the assets by the time the assets are taken out of service. The 5-year amortization is $86,569 annually for UES.

Q. In your opinion, are the depreciation rates set forth in Exhibit NWA-3 the appropriate rates for the Commission to adopt in this proceeding for UES?

A. Yes. These rates appropriately reflect the rates at which the value of UES's assets are being consumed over their useful lives. These rates are an appropriate basis for setting electric rates in this matter and for the Company to use for booking depreciation and amortization expense going forward.

Q. Does this conclude your direct testimony?

A. Yes.

NED W. ALLIS

DEPRECIATION EXPERIENCE

Q. Please state your name.

A. My name is Ned W. Allis.

Q. What is your educational background?

A. I have a Bachelor of Science degree in Mathematics from Lafayette College in Easton, PA.

Q. Do you belong to any professional societies?

A. Yes. I am a member and past President of the Society of Depreciation Professionals ("Society") and an associate member of the American Gas Association/Edison Electric Institute Industry Accounting Committee. I also serve on the faculty for training offered by the Society and am an instructor for the Society's "Introduction to Depreciation," "Life and Net Salvage Analysis," "Analyzing the Life of Real-World Property," "Analyzing Net Salvage in the Real World" and "Depreciation and Ratemaking Issues" courses.

Q. Do you hold any special certification as a depreciation expert?

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 2011 and was recertified in March 2017.

Q. Please outline your experience in the field of depreciation.

A. I joined Gannett Fleming in October 2006 as an analyst. My responsibilities included assembling data required for depreciation studies, conducting statistical analyses of service life and net salvage data, calculating annual and accrued depreciation, and assisting in preparing reports and testimony setting forth and defending the results of the studies. I also developed and maintained Gannett Fleming's proprietary depreciation software. In March 2013, I was promoted to the position of Supervisor of Depreciation Studies. In March 2017, I was promoted to Project Manager, Depreciation and Technical Development. In January 2019, I was promoted to my current position of Vice President. In my current position, I am responsible for conducting depreciation, valuation and original cost studies, determining service life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to clients, and supporting such rates before state and federal regulatory agencies. I am also responsible for Gannett Fleming's proprietary depreciation software, training of depreciation staff, and the development of solutions for technical issues related to depreciation. Since joining Gannett Fleming, I have worked on more than one hundred depreciation assignments.

Q. Have you previously submitted testimony to the New Hampshire Public Utilities Commission?

A. Yes.

Q. Have you submitted testimony to any other state utility commission on the subject of utility plant depreciation?

A. Yes. I have submitted testimony on depreciation related topics to the Connecticut Public Utilities Regulatory Authority, the New York Department of Public Service, the New Jersey Board of Public Utilities, the Nevada Public Utilities Commission, the Florida Public Service Commission, the District of Columbia Public Service Commission, the California Public Utilities Commission, the Rhode Island Public Utilities Commission, the Massachusetts Department of Public Utilities and the Maryland Public Service

Commission. I have also testified before the Federal Energy Regulatory Commission ("FERC").

Q. Have you had any additional education relating to utility plant depreciation?

A. Yes. I have completed the following courses conducted by the Society: "Depreciation Basics," "Life and Net Salvage Analysis" and "Preparing and Defending a Depreciation Study."

Q. Does this conclude your qualification statement?

A. Yes.

LIST OF CASES IN WHICH NED W. ALLIS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client/Utility	Subject
01.	2013	NV	13-06004	Sierra Pacific Power Company	Depreciation
02.	2013	NY	13-E-0030, 13-G-0031 & 13-S-0032	Consolidated Edison Company of New York	Depreciation
03.	2013	DC	Case No. 1103	Pepco	Depreciation
04.	2014	NY	14-G-0494	Orange and Rockland - Gas	Depreciation
05.	2014	NY	14-E-0493	Orange and Rockland - Electric	Depreciation
06.	2014	NY	15-E-0050	Consolidated Edison Company of New York - Electric	Depreciation
07.	2015	FERC	ER15-2294-000	Pacific Gas & Electric Company TO17	Depreciation
08.	2015	NY	16-E-0060	Consolidated Edison Company of New York - Electric	Depreciation
09.	2015	NY	16-G-0061	Consolidated Edison Company of New York - Gas	Depreciation
10.	2016	FL	160021-EI	Florida Power & Light Company	Depreciation
11.	2016	NV	16-06008	Sierra Pacific Power Company - Electric	Depreciation
12.	2016	NV	16-06009	Sierra Pacific Power Company - Gas	Depreciation
13.	2016	NJ	ER 16050428	Rockland Electric Company	Depreciation
14.	2016	FERC	ER16-2320-000	Pacific Gas & Electric Company – Electric Transmission	Depreciation
15.	2016	DC	Case No. 1139	Pepco	Depreciation
16.	2017	NV	17-06004	Nevada Power Company	Depreciation
17.	2017	FERC	ER17-2154-000	Pacific Gas & Electric Company – Electric Transmission	Depreciation
18.	2017	CT	17-10-46	Connecticut Light & Power	Depreciation
19.	2017	CA	A.17-11-009	Pacific Gas & Electric – Gas Transmission and Storage	Depreciation
20.	2017	RI	4770	Narragansett Electric Company	Depreciation
21.	2017	DC	Case No. 1150	Pepco	Depreciation
22.	2018	CT	18-05-10	Yankee Gas Services Company	Depreciation
23.	2018	NY	18-E-0067	Orange and Rockland – Electric	Depreciation
24.	2018	NY	18-G-0068	Orange and Rockland – Gas	Depreciation
25.	2018	NJ	ER18080925	Atlantic City Electric Company	Depreciation
26.	2018	FERC	ER19-13-000	Pacific Gas & Electric Company – Electric Transmission	Depreciation
27.	2018	FERC	ER19-284-000	Florida Power & Light Company	Depreciation
28.	2018	CA	A. 18-12-009	Pacific Gas & Electric Company	Depreciation

	Year	Jurisdiction	Docket No.	Client/Utility	Subject
29.	2018	NY	19-E-0065	Consolidated Edison Company of New York - Electric	Depreciation
30.	2018	NY	19-G-0065	Consolidated Edison Company of New York - Gas	Depreciation
31.	2019	MA	D.P.U. 18-150	Massachusetts Electric Company	PBR / Depreciation
32.	2019	MD	9610	Baltimore Gas & Electric Company	Depreciation
33.	2019	KS	19-ATMG-525-RTS	Atmos Energy	Depreciation
34.	2020	MA	D.P.U. 20-120	Boston Gas Company	Depreciation
35.	2020	FERC	ER20-2878-00	PG&E – Wholesale Distribution	Depreciation
36.	2020	NH	DW 20-184	Aquarion Water Company	Depreciation
37.	2021	FERC	RP21-100-000	National Grid Liquified Natural Gas	Depreciation
38.	2021	FL	20210016-EI	Duke Energy Florida	Depreciation
39.	2021	NY	21-E-0074	Orange and Rockland – Electric	Depreciation
40.	2021	NY	21-G-0073	Orange and Rockland – Gas	Depreciation
41.	2021	FERC	ER21-83-000	Pepco	Depreciation
42.	2021	FL	20210015-EI	Florida Power & Light Company	Depreciation

UNITIL ENERGY SYSTEMS, INC.

HAMPTON, NEW HAMPSHIRE

2020 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO ELECTRIC PLANT
AS OF DECEMBER 31, 2020

Prepared by:

Gannett Fleming

Excellence Delivered ***As Promised***

UNITIL ENERGY SYSTEMS, INC.

Hampton, New Hampshire

2020 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO ELECTRIC PLANT
AS OF DECEMBER 31, 2020

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC

Camp Hill, Pennsylvania

Gannett Fleming

Excellence Delivered ***As Promised***

March 19, 2021

Unitil Energy Systems, Inc.
6 Liberty Lane West
Hampton, NH 03842

Attention Mr. Dan Main
Manager of Regulatory Services and Corporate Compliance

Ladies and Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the electric plant of Unitil Energy Systems, Inc. as of December 31, 2020. The attached report presents a description of the methods used in the estimation of depreciation, the summary of annual depreciation accrual rates, the statistical support for the life and net salvage estimates and the detailed tabulations of annual depreciation.

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC.

NED W. ALLIS, CDP
Vice President

NWA:mle

068036

Gannett Fleming Valuation and Rate Consultants, LLC
207 Senate Avenue • Camp Hill, PA 17011-2316
t: 717.763.7211 • f: 717.763.4590

www.gfvrc.com

TABLE OF CONTENTS

TABLE OF CONTENTS, cont.

UNITIL ENERGY SYSTEMS, INC.

DEPRECIATION STUDY

EXECUTIVE SUMMARY

Pursuant to Unitil Energy Systems, Inc. ("Unitil" or "Company") request, Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") conducted a depreciation study related to the electric plant of Unitil as of December 31, 2020. The purpose of this study was to determine the annual depreciation accrual rates and amounts for book and ratemaking purposes.

The depreciation rates are based on the straight line method using the average service life ("ASL") procedure and were applied on a remaining life basis. The calculations were based on attained ages and estimated average service life and forecasted net salvage characteristics for each depreciable group of assets.

The recommendations in the depreciation study are for changes to service life and net salvage estimates for various accounts. In the aggregate, the overall impact of the recommended depreciation rates is a moderate change in depreciation expense. The most significant change in the depreciation study is the use of actuarial data for life analysis. Amortization accounting is also recommended for many general plant accounts.

In previous studies, the Simulated Plant Record (SPR) method was used for the historical analysis of service lives. For the current study, aged data was available for the period 2010 through 2020. In order to analyze data for a longer period of time, unaged data for the period of 1995 to 2009 was statistically aged and incorporated into the actuarial life analysis. While generally the study resulted in increases in service lives for many accounts, this was partially offset by more negative net salvage for many accounts. The overall result of the study is a decrease in depreciation expense.

Gannett Fleming recommends the calculated annual depreciation accrual rates set forth herein apply specifically to electric plant in service as of December 31, 2020 as summarized by Table 1 of the study. Supporting analysis and calculations are provided within the study.

The study results set forth an annual depreciation expense of approximately $12.8 million for electric plant when applied to depreciable plant balances as of December 31, 2020. The results are summarized at the functional level as follows:

SUMMARY OF ORIGINAL COST, ACCRUAL RATES AND AMOUNTS

FUNCTION	ORIGINAL COST	ACCRUAL RATE	ANNUAL ACCRUAL
ELECTRIC PLANT			
PRODUCTION PLANT	$ 56,575.22	18.66	$ 10,559
DISTRIBUTION PLANT	352,255,384.31	3.39	11,945,637
GENERAL PLANT	28,981,728.90	2.62	760,082
RESERVE ADJUSTMENT FOR AMORTIZATION			86,569
TOTAL DEPRECIABLE PLANT	**$381,293,688.43**	3.36	**12,802,847**

PART I. INTRODUCTION

UNITIL ENERGY SYSTEMS, INC.
DEPRECIATION STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for Unitil Energy Systems, Inc. ("Unitil" or "Company"), to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of electric plant as of December 31, 2020. The rates and amounts are based on the straight line remaining life method of depreciation. This report also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to electric plant in service as of December 31, 2020.

The service life and net salvage estimates resulting from the study were based on informed judgment which incorporated analyses of historical plant retirement data as recorded through 2020, a review of Company practice and outlook as they relate to plant operation and retirement, and consideration of current practice in the electric industry, including knowledge of service lives and net salvage estimates used for other electric companies.

PLAN OF REPORT

Part I, Introduction, contains statements with respect to the plan of the report, and the basis of the study. Part II, Estimation of Survivor Curves, presents descriptions of the considerations and methods used in the service life study. Part III, Service Life Considerations, presents the results of the average service life analysis. Part IV, Net Salvage Considerations, presents the results of the net salvage study. Part V, Calculation of Annual and Accrued Depreciation, describes the procedures used in the calculation of group depreciation. Part VI, Results of Study, presents summaries by depreciable group of annual depreciation accrual rates and amounts, as well as composite remaining lives. Part VII, Service Life Statistics presents the statistical analysis of service life estimates, Part VIII, Net Salvage Statistics sets forth the statistical indications of net salvage percents, and Part IX, Detailed Depreciation Calculations presents the detailed tabulations of annual depreciation.

BASIS OF THE STUDY

Depreciation

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirements of public authorities.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing electric services. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight line method of depreciation.

For most accounts, the annual depreciation was calculated by the straight-line method using the average service life procedure and the remaining life basis. For certain General Plant accounts, the annual depreciation is based on amortization accounting.

Both types of calculations were based on original cost, attained ages, and estimates of service lives and net salvage.

The straight line method, average service life procedure is a commonly used depreciation calculation procedure that has been widely accepted in jurisdictions throughout North America. Gannett Fleming recommends its use in this study. Amortization accounting is used for certain General Plant accounts because of the disproportionate plant accounting effort required when compared to the minimal original cost of the large number of items in these accounts. An explanation of the calculation of annual and accrued amortization is presented beginning on page V-3 of the report.

Service Life and Net Salvage Estimates

The service life and net salvage estimates used in the depreciation and amortization calculations were based on informed judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the electric industry, and comparisons of the service life and net salvage estimates from our studies of other electric utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for electric plant. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

PART II. ESTIMATION OF SURVIVOR CURVES

PART II. ESTIMATION OF SURVIVOR CURVES

The calculation of annual depreciation based on the straight line method requires the estimation of survivor curves and the selection of group depreciation procedures. The estimation of survivor curves is discussed below and the development of net salvage is discussed in later sections of this report.

SURVIVOR CURVES

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages.

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

This study has incorporated the use of Iowa curves developed from a retirement rate analysis of historical retirement history. A discussion of the concepts of survivor curves and of the development of survivor curves using the retirement rate method is presented below.

Iowa Type Curves

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves,

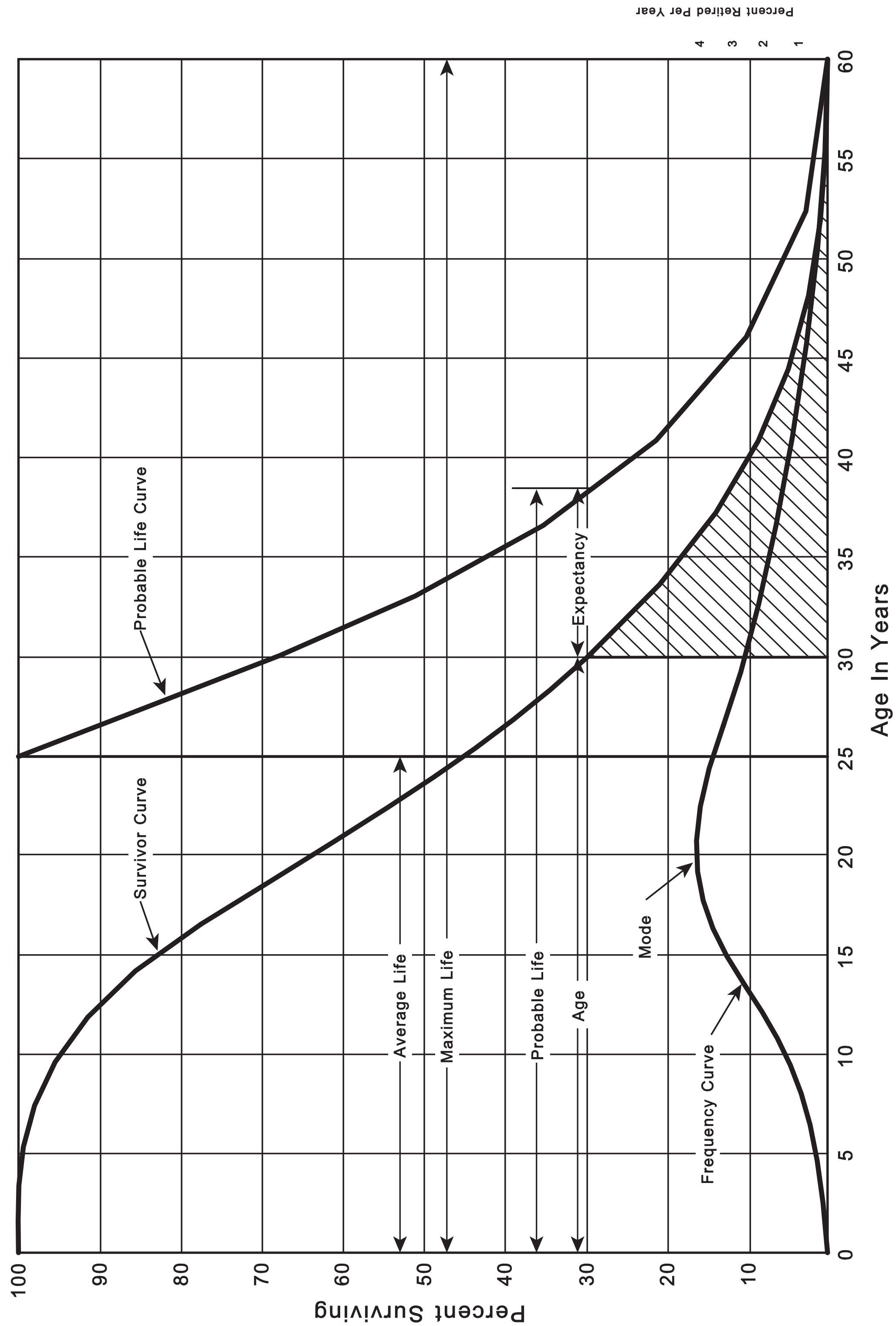


Figure 1. A Typical Survivor Curve and Derived Curves

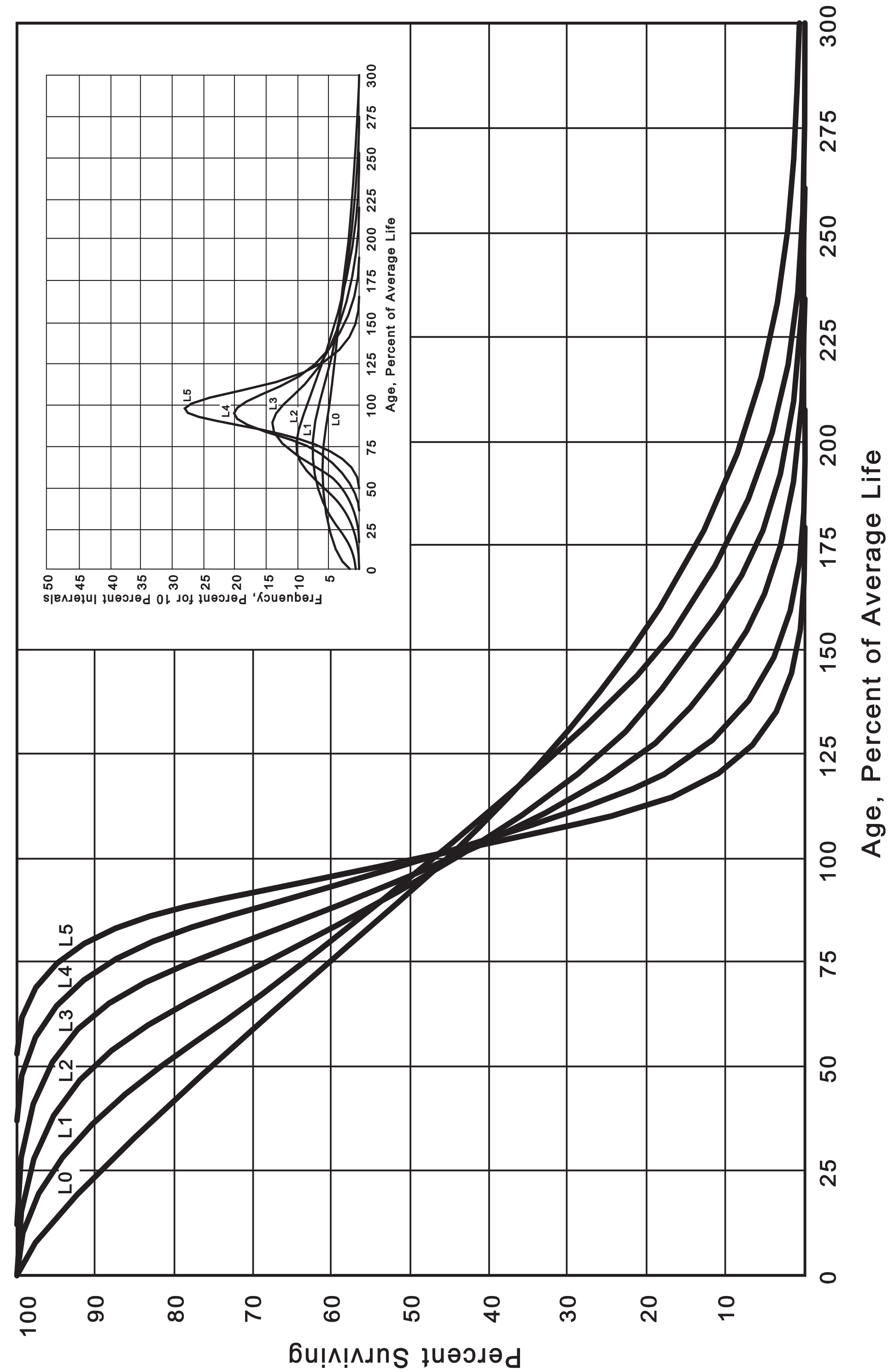


Figure 2. Left Modal or "L" Iowa Type Survivor Curves

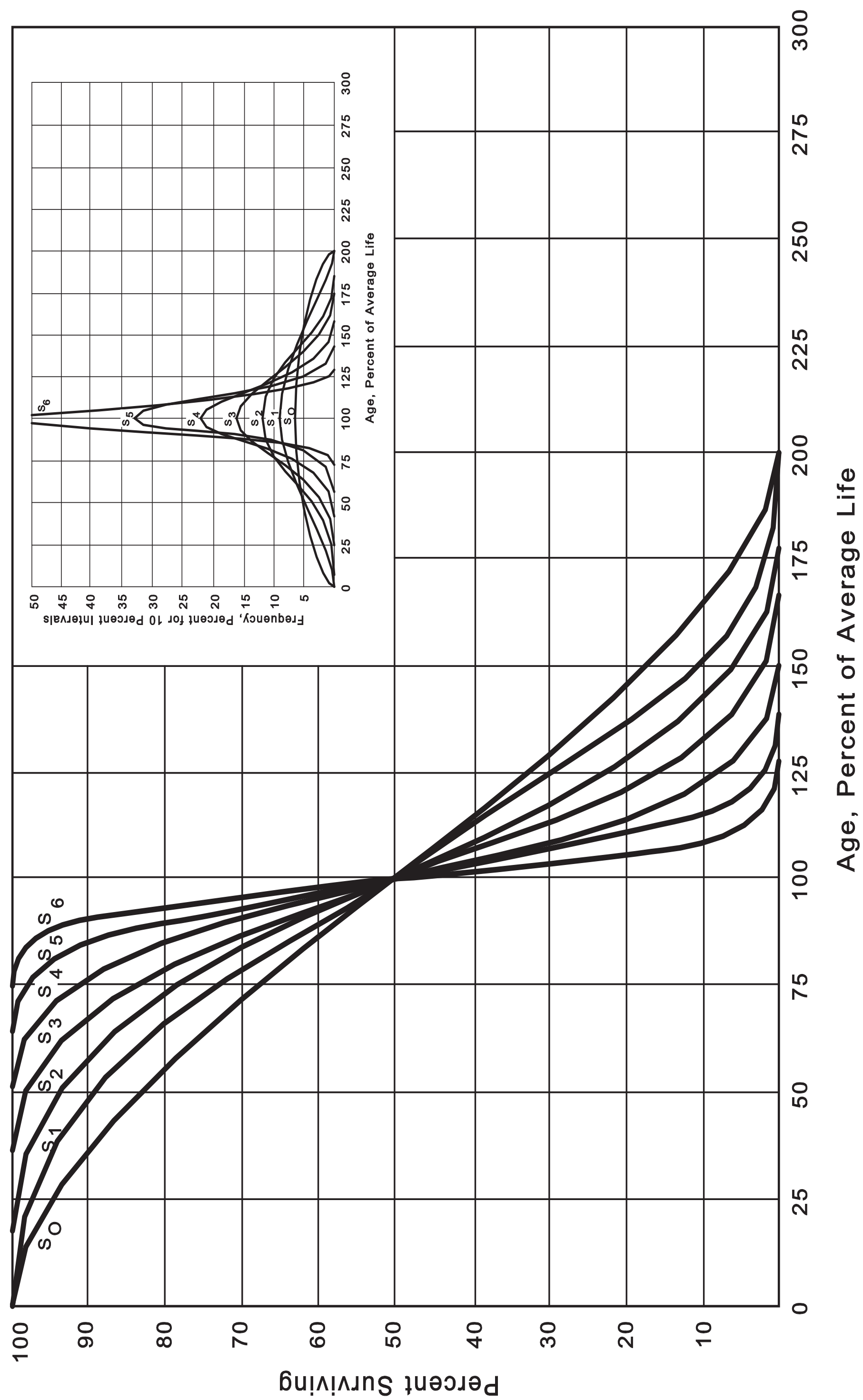


Figure 3. Symmetrical or "S" Iowa Type Survivor Curves

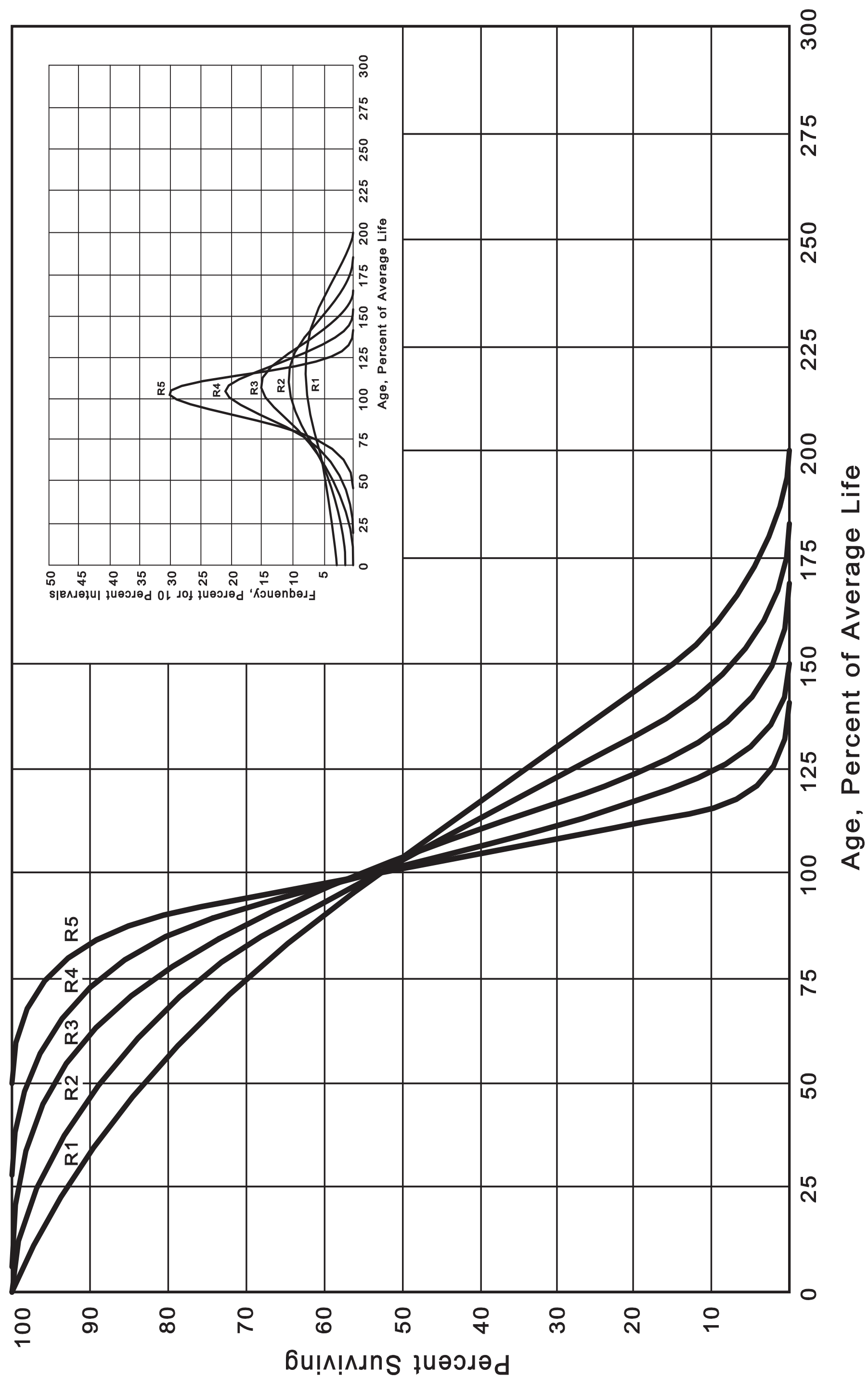


Figure 4. Right Modal or "R" Iowa Type Survivor Curves

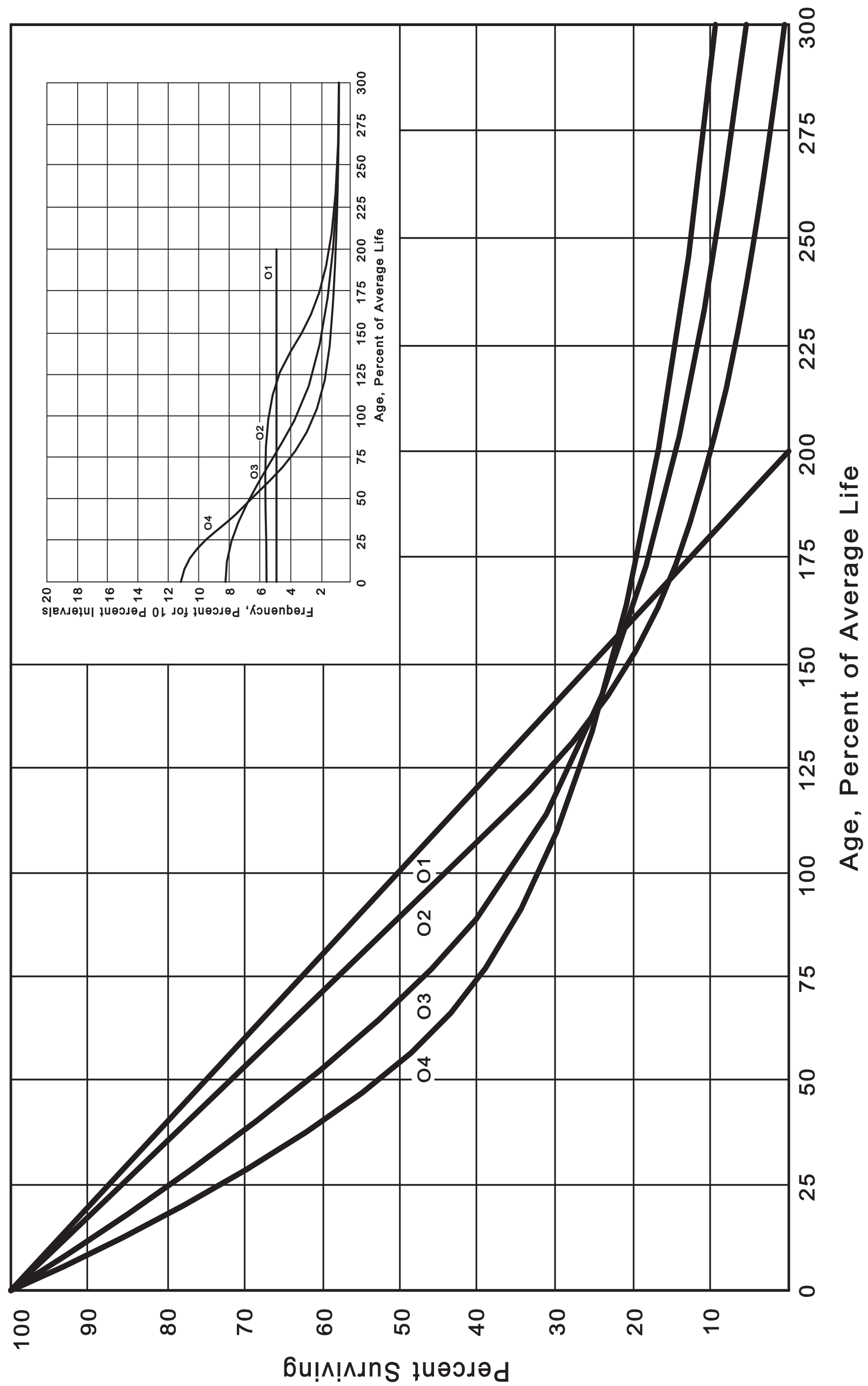


Figure 5. Origin Modal or "O" Iowa Type Survivor Curves

which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125. These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[1] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student submitted a thesis presenting his development of the fourth family consisting of the four O type survivor curves.

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text, and is also explained in several publications, including "Statistical Analyses of Industrial Property Retirements,"[2] "Engineering Valuation and Depreciation,"[3] and "Depreciation Systems."[4]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the experience band, and the band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows. The example includes schedules of annual

[1]Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.
[2]Winfrey, Robley, Statistical Analyses of Industrial Property Retirement. Iowa State College Engineering Experiment Station, Bulletin 125. 1935.
[3]Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 1.
[4]Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2011-2020 during which there were placements during the years 2006-2020. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Schedules 1 and 2 on pages II-11 and II-12. In Schedule 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the dollars invested in 2006 were retired in 2011. The $10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2011 retirements of 2006 installations and ending with the 2020 retirements of the 2015 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

$$10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.$$

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2011-2020
SUMMARIZED BY AGE INTERVAL

Experience Band 2011-2020 Placement Band 2006-2020

Year Placed (1)	2011 (2)	2012 (3)	2013 (4)	2014 (5)	2015 (6)	2016 (7)	2017 (8)	2018 (9)	2019 (10)	2020 (11)	Total During Age Interval (12)	Age Interval (13)
	Retirements, Thousands of Dollars During Year											
2006	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2007	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2008	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2009	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2010	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2011	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2012		5	11	12	13	14	15	16	18	20	113	7½-8½
2013			6	12	13	15	16	17	19	19	124	6½-7½
2014				6	13	15	16	17	19	19	131	5½-6½
2015					7	14	16	17	19	20	143	4½-5½
2016						8	18	20	22	23	146	3½-4½
2017							9	20	22	25	150	2½-3½
2018								11	23	25	151	1½-2½
2019									11	24	153	½-1½
2020										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2011-2020
SUMMARIZED BY AGE INTERVAL

Experience Band 2011-2020

Placement Band 2006-2020

	Acquisitions, Transfers and Sales, Thousands of Dollars During Year											
Year Placed (1)	2011 (2)	2012 (3)	2013 (4)	2014 (5)	2015 (6)	2016 (7)	2017 (8)	2018 (9)	2019 (10)	2020 (11)	Total During Age Interval (12)	Age Interval (13)
2006	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2007	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2008	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2009	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2010	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2011	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2012		-	-	-	-	-	-	-	-	-	6	7½-8½
2013			-	-	-	-	-	-	-	-	-	6½-7½
2014				-	-	-	-	(12)[b]	-	-	-	5½-6½
2015					-	-	-	-	22[a]	-	-	4½-5½
2016						-	-	(19)[b]	-	-	10	3½-4½
2017							-	-	-	-	-	2½-3½
2018								-	-	(102)[c]	(121)	1½-2½
2019									-	-	-	½-1½
2020											-	0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses Denote Credit Amount.

In Schedule 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 on page II-14. The surviving plant at the beginning of each year from 2011 through 2020 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2016 are calculated in the following manner:

Exposures at age 0	= amount of addition	= $750,000
Exposures at age ½	= $750,000 - $ 8,000	= $742,000
Exposures at age 1½	= $742,000 - $18,000	= $724,000
Exposures at age 2½	= $724,000 - $20,000 - $19,000	= $685,000
Exposures at age 3½	= $685,000 - $22,000	= $663,000

SCHEDULE 3. PLANT EXPOSED TO RETIREMENT
JANUARY 1 OF EACH YEAR 2011-2020
SUMMARIZED BY AGE INTERVAL

Experience Band 2011-2020 | Placement Band 2006-2020

Year	Exposures, Thousands of Dollars: Annual Survivors at the Beginning of the Year										Total at	
Placed	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Beginning of Age Interval	Age Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2006	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2007	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2008	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2009	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2010	376	367	357	346	334	321	307	297	280	261	1,097	9½-10½
2011	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2012		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2013			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2014				580[a]	574	561	546	530	501	482	3,057	5½-6½
2015					660[a]	653	639	623	628	609	3,789	4½-5½
2016						750[a]	742	724	685	663	4,332	3½-4½
2017							850[a]	841	821	799	4,955	2½-3½
2018								960[a]	949	926	5,719	1½-2½
2019									1,080[a]	1,069	6,579	½-1½
2020										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a]Additions during the year

For the entire experience band 2011-2020, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table

The original life table, illustrated in Schedule 4 on page II-16, is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15				
Exposures at age 4½	=	3,789,000				
Retirements from age 4½ to 5½	=	143,000				
Retirement Ratio	=	143,000	÷	3,789,000	=	0.0377
Survivor Ratio	=	1.000	-	0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15)	x	(0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless.

SCHEDULE 4. ORIGINAL LIFE TABLE CALCULATED
BY THE RETIREMENT RATE METHOD

Experience Band 2011-2020 Placement Band 2006-2020

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving at Beginning of Age Interval
(1)	(2)	(3)	(4)	(5)	(6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	44,780	1,606			

Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
Column 3 from Schedule 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 Divided by Column 2.
Column 5 = 1.0000 Minus Column 4.
Column 6 = Column 5 Multiplied by Column 6 as of the Preceding Age Interval.

The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

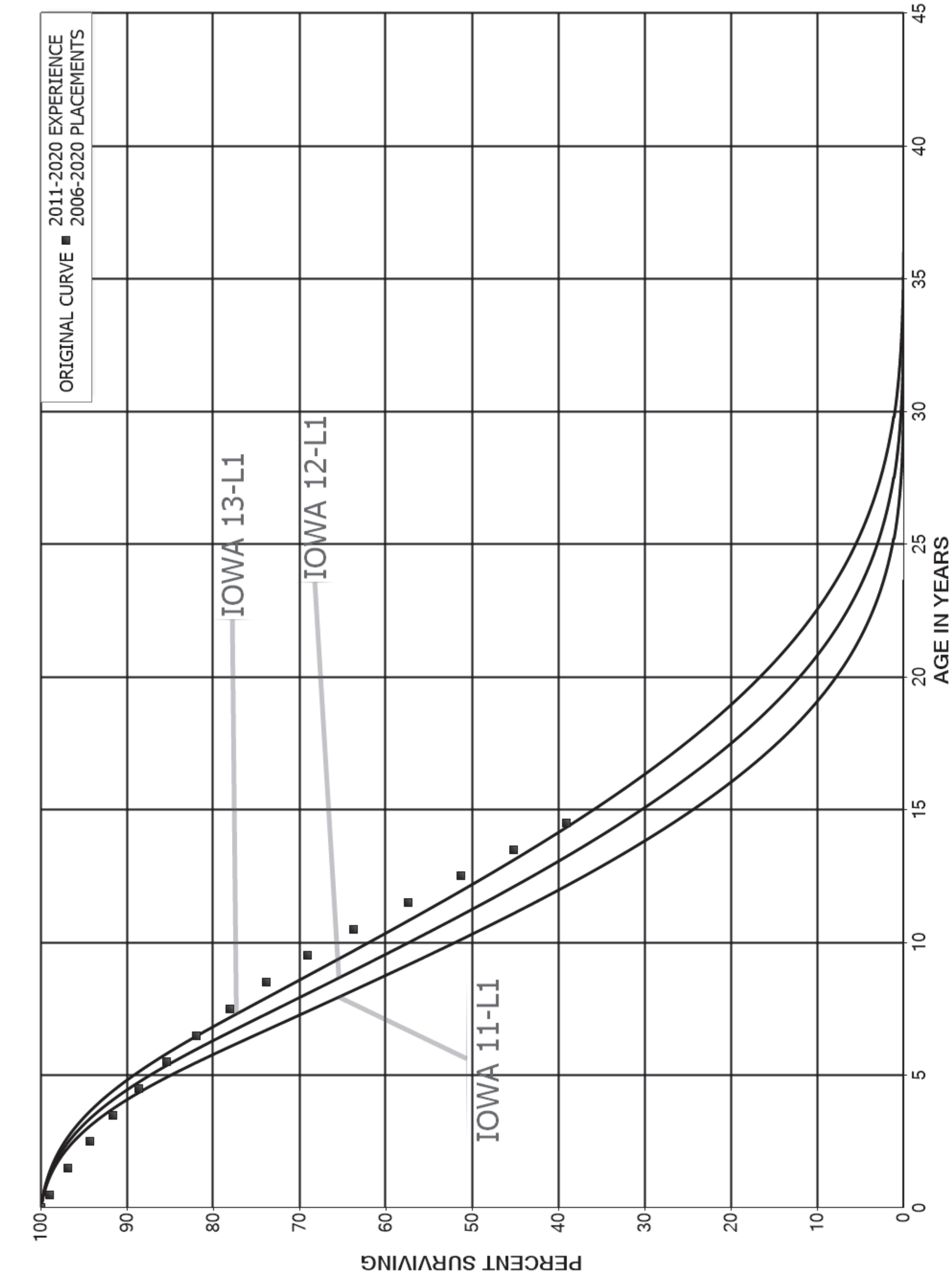


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

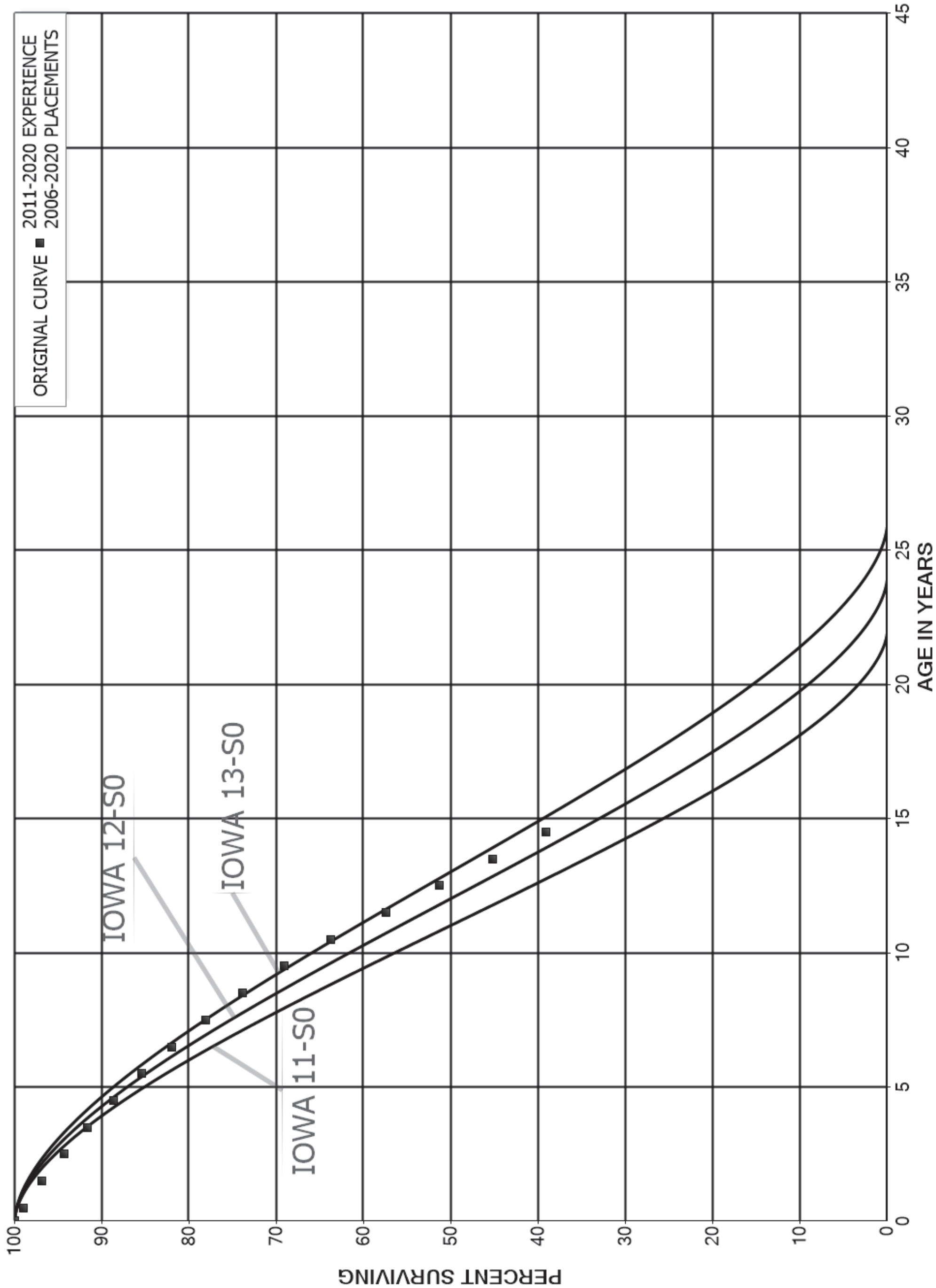


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

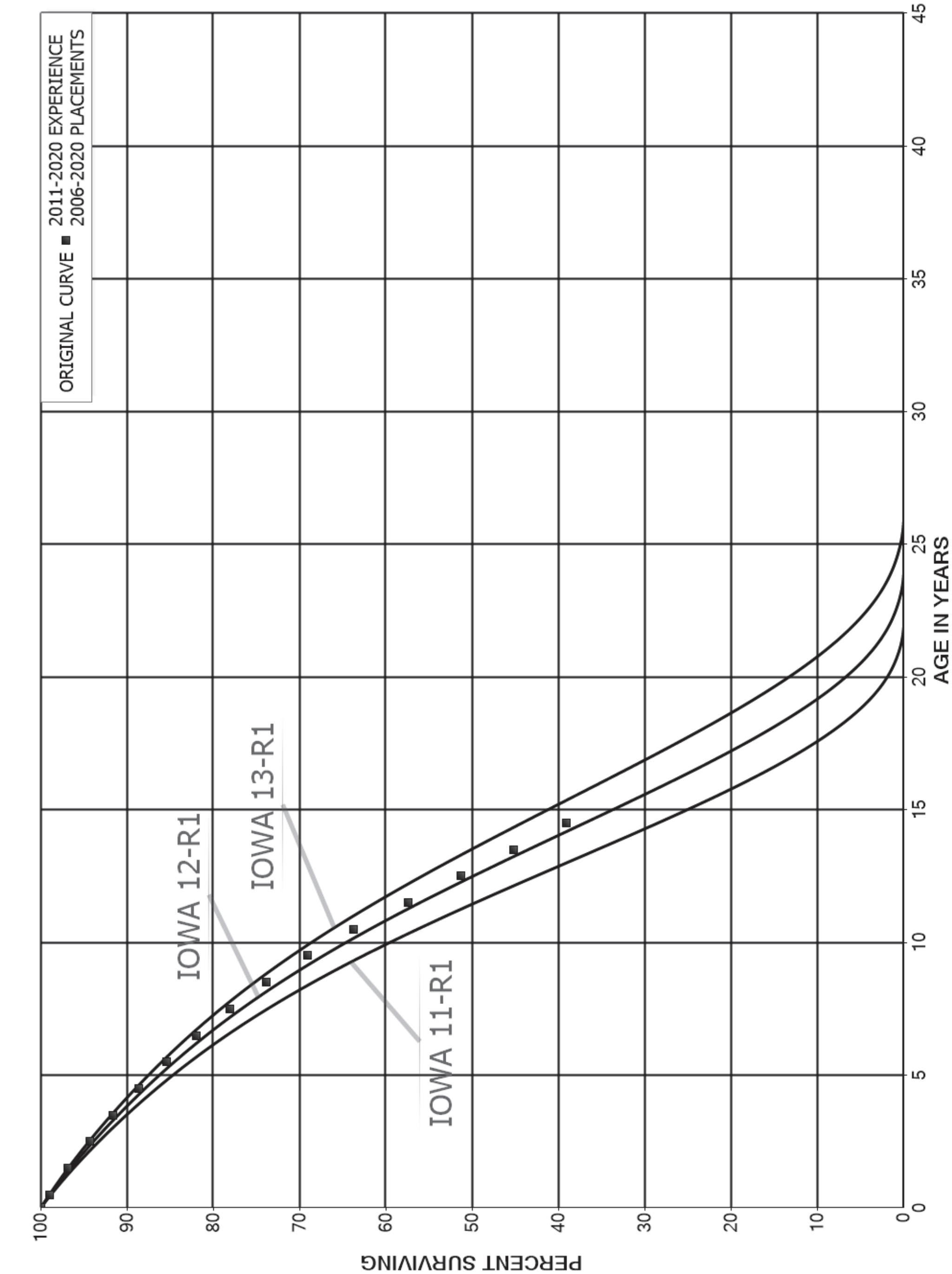
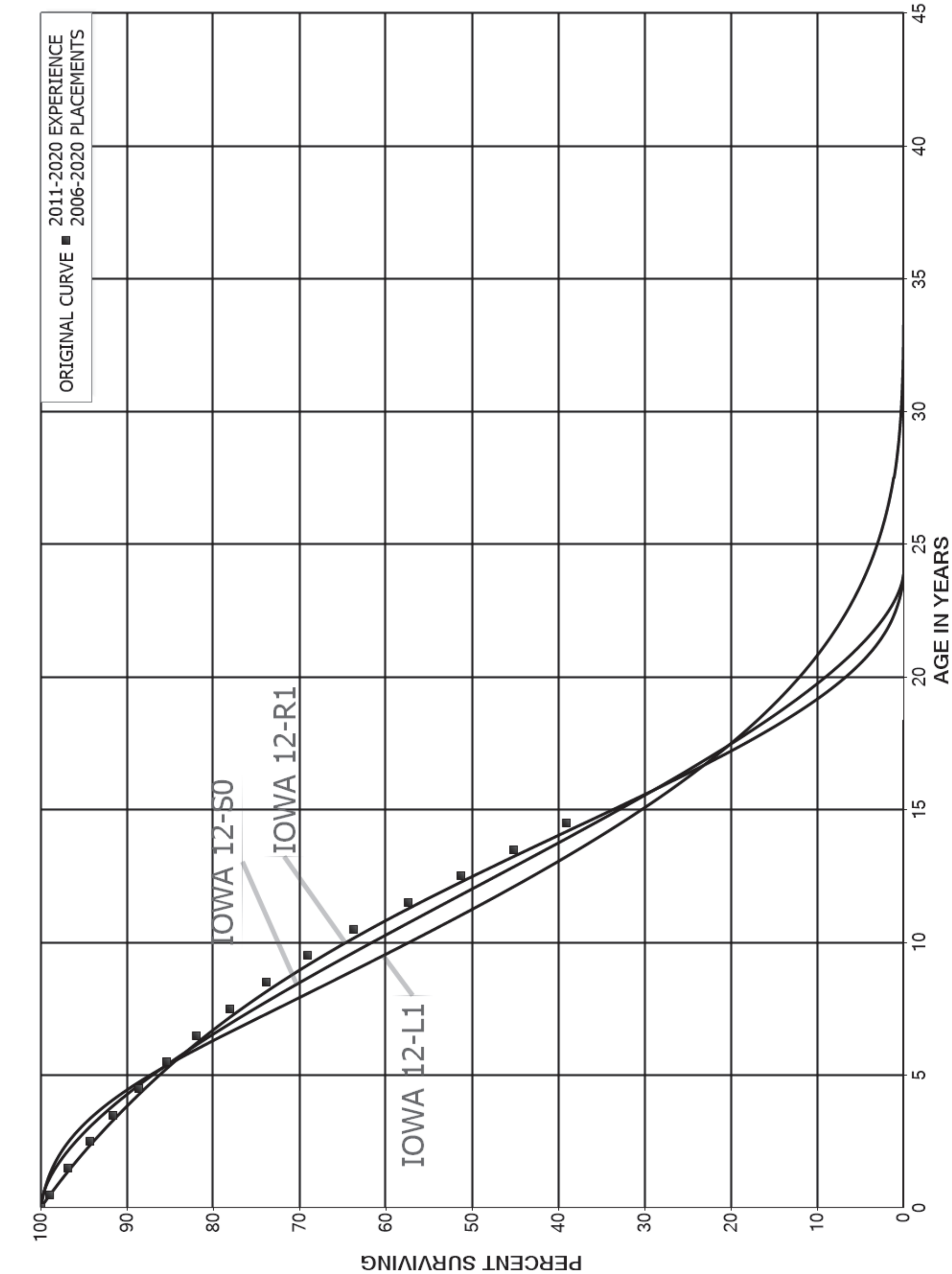


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



PART III. SERVICE LIFE CONSIDERATIONS

PART III. SERVICE LIFE CONSIDERATIONS

FIELD TRIPS

In order to be familiar with the operation of the Company and observe representative portions of the plant, field trips are normally conducted for Gannett Fleming's depreciation studies. For this study, due to restrictions in place as a result of COVID-19, a field trip was not feasible. However, the Company was able to provide virtual field trips for the study. A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements are obtained during these virtual field trips as well as with meetings with Company personnel. This knowledge and information were incorporated in the interpretation and extrapolation of the statistical analyses.

The following is a list of the locations visited during the most recent field trip.

February 18, 2021

Kingston Substation
Guinea Substation

SERVICE LIFE ANALYSIS

The service life estimates were based on informed judgment which considered a number of factors. The primary factors were the statistical analyses of data; current Company policies and outlook as determined during conversations with management; and the survivor curve estimates from previous studies of this company and other electric companies. For the statistical analysis, aged data were available from 2010 through 2020. In part because this is a relatively short period of time when compared to the full life cycle of many of the Company's assets, the aged data was supplemented with statistically aged data for years prior to 2010. The data for the years prior to 2010 were the unaged data used in prior depreciation studies and were statistically aged using the historical unaged activity and the currently approved Iowa survivor curve types. The resulting database allowed for the study of data using the retirement rate method from 1995 through 2020 for most accounts.

For many of the plant accounts and subaccounts for which survivor curves were estimated, the statistical analyses using the retirement rate method resulted in good to excellent indications of the survivor patterns experienced. These accounts represent approximately 86 percent of depreciable plant. Generally, the information external to the statistical analysis led to no significant departure from the indicated survivor curves for the accounts listed below. The statistical support for the service life estimates is presented in the section beginning on page VII-2.

DISTRIBUTION PLANT

361	Structures and Improvements
362	Station Equipment
364	Poles, Towers and Fixtures
365	Overhead Conductors and Devices
366	Underground Conduit
367	Underground Conductors and Devices
368	Line Transformers
368.01	Line Transformers Installations
371	Installations on Customers' Premises
373	Street Lighting and Signal Systems

GENERAL PLANT

390	Structures and Improvements

Account 364, Poles, Towers and Fixtures is one of the largest electric accounts and is used to illustrate the manner in which the study was conducted for the groups using the retirement rate method. Aged retirement data was available from 2010 through 2020. These data were coded in the course of the Company's normal recordkeeping according to plant account or property group, type of transaction, year in which the transaction took place, and year in which the electric plant was placed in service. Statistically aged data was also available from 1995 through 2009. Both the full range of data from 1995 through 2020 and the aged data from 2010 through 2020 were analyzed using the retirement rate method.

Retirements for poles typically occur due to decay, damage, clearances, relocations and as the result of the Company's pole inspection program. The current survivor curve estimate for this account is the 41-S1. The retirement rate analysis indicates a longer service life than the current estimate. A chart depicting the estimated 50-R1.5 survivor curve and original life tables used as the basis for the estimate are presented on page VII-15 of the study. The original life tables depicted on the chart are presented on the pages that follow the chart. Typical estimates in the industry for poles, towers and fixtures range from 40 to 60 years. The recommended 50-R1.5 survivor curve is a good fit of the historical data, is consistent with the expectations of Company personnel, and is within the range of typical estimates for this type of property.

Similar studies were performed for the remaining plant accounts. Each of the judgments represented a consideration of statistical analyses of aged plant activity, management's outlook for the future, and the typical range of lives used by other electric companies.

The selected amortization periods for other General Plant accounts are described in the section "Calculated Annual and Accrued Amortization."

PART IV. NET SALVAGE CONSIDERATIONS

PART IV. NET SALVAGE CONSIDERATIONS

NET SALVAGE ANALYSIS

The estimates of net salvage by account were based in part on historical data compiled for the years 1995 through 2020. Cost of removal and gross salvage were expressed as percents of the original cost of plant retired, both on annual and three-year moving average bases. The most recent five-year average also was calculated for consideration. The net salvage estimates by account are expressed as a percent of the original cost of plant retired.

<u>Net Salvage Considerations</u>

The estimates of future net salvage are expressed as percentages of surviving plant in service, i.e., all future retirements. In cases in which removal costs are expected to exceed salvage receipts, a negative net salvage percentage is estimated. The net salvage estimates were based on judgment which incorporated analyses of historical cost of removal and salvage data, expectations with respect to future removal requirements and markets for retired equipment and materials.

The analyses of historical cost of removal and salvage data are presented in the section titled “Net Salvage Statistics” for the plant accounts for which the net salvage estimate relied partially on those analyses.

Statistical analyses of historical data for the period 1995 through 2020 contributed significantly toward the net salvage estimates for 11 plant accounts, representing approximately 97 percent of the depreciable plant. However, it should be noted that while the historical data was a basis for the estimates shown in the table below, some of the estimates are conservative (i.e. less negative) when compared to the historical data and represent gradual changes from the existing net salvage estimates. These considerations will be discussed in more detail below.

DISTRIBUTION PLANT

362	Station Equipment
364	Poles, Towers and Fixtures
365	Overhead Conductors and Devices
366	Underground Conduit
367	Underground Conductors and Devices
368	Line Transformers
368.01	Line Transformers Installations
369	Services
370	Meters
370.01	Meter Installations
371	Installations on Customers' Premises
373	Street Lighting and Signal Systems

GENERAL PLANT

390	Structures and Improvements

The net salvage estimate for Account 364, Poles, Towers and Fixtures, will be used to illustrate the methods for estimating net salvage. The current net salvage estimate is negative 51.5 percent. The historical data indicates a more negative estimate than the current estimate. The overall average net salvage is negative 84 percent. The most recent five-year average is negative 79 percent. Based on the historical data and the expectations provided by management for this account, a more negative net salvage estimate is recommended. Based on the overall average and the most recent five-year average a change to negative 80 percent, which is within the range of estimates used by other electric companies, is recommended at this time.

The net salvage estimates for the remaining plant accounts were estimated using the above-described process of historical indications, judgment and reviewing the typical range of estimates used by other electric companies. The results of the net salvage for each plant account are presented in account sequence in the section titled "Net Salvage Statistics", beginning on page VIII-2.

Generally, the net salvage estimates for the accounts subject to general plant amortization were zero percent, consistent with amortization accounting.

PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

GROUP DEPRECIATION PROCEDURES

A group procedure for depreciation is appropriate when considering more than a single item of property. Normally the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, average service life and equal life group. In the average service life procedure, the rate of annual depreciation is based on the average life or average remaining life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

<u>Single Unit of Property</u>

The calculation of straight line depreciation for a single unit of property is straightforward. For example, if a $1,000 unit of property attains an age of four years and has a life expectancy of six years, the annual accrual over the total life is:

$$\frac{\$1{,}000}{(4 + 6)} = \$100 \text{ per year.}$$

The accrued depreciation is:

$$\$1{,}000\left(1 - \frac{6}{10}\right) = \$400.$$

Remaining Life Annual Accruals

For the purpose of calculating remaining life accruals as of December 31, 2020, the depreciation reserve for each plant account is allocated among vintages in proportion to the calculated accrued depreciation for the account. Explanations of remaining life accruals and calculated accrued depreciation follow. The detailed calculations as of December 31, 2020, are set forth in the Results of Study section of the report.

Average Service Life Procedure

In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated future survivor curve in accordance with the average service life procedure.

The calculated accrued depreciation for each depreciable property group represents that portion of the depreciable cost of the group which would not be allocated to expense through future depreciation accruals if current forecasts of life characteristics are used as the basis for such accruals. The accrued depreciation calculation consists of applying an appropriate ratio to the surviving original cost of each vintage of each account based upon the attained age and service life. The straight line accrued depreciation ratios are calculated as follows for the average service life procedure:

$$Ratio = 1 - \frac{Average\ Remaining\ Life}{Average\ Service\ Life}.$$

CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is proposed for a number of accounts that represent numerous units of property, but a very small portion of depreciable electric plant in service. The accounts and their amortization periods are as follows:

ACCT	TITLE	AMORTIZATION PERIOD, YEARS
391.01	Office Furniture and Equipment	15
393.00	Stores Equipment	25
394.00	Tools, Shop and Garage Equipment	25
395.00	Laboratory Equipment	25
397.00	Communication Equipment	15
398.00	Miscellaneous Equipment	20

For the purpose of calculating annual amortization amounts as of December 31, 2020, the book depreciation reserve for each plant account or subaccount is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

PART VI. RESULTS OF STUDY

PART VI. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The calculated annual and accrued depreciation are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service. The annual accrual rates were calculated in accordance with the straight line remaining life method of depreciation, using the average service life procedure based on estimates which reflect considerations of current historical evidence and expected future conditions.

The annual depreciation accrual rates are applicable specifically to the electric plant in service as of December 31, 2020. For most plant accounts, the application of such rates to future balances that reflect additions subsequent to December 31, 2020, is reasonable for a period of three to five years.

DESCRIPTION OF DETAILED TABULATIONS

The service life estimates were based on judgment that incorporated statistical analysis of retirement data, discussions with management and consideration of estimates made for other electric utilities. The results of the statistical analysis of service life are presented in the section beginning on page VII-2, within the supporting documents of this report.

For each depreciable group analyzed by the retirement rate method, a chart depicting the original and estimated survivor curves followed by a tabular presentation of the original life table(s) plotted on the chart. The survivor curves estimated for the depreciable groups are shown as dark smooth curves on the charts. Each smooth survivor curve is denoted by a numeral followed by the curve type designation. The numeral used is the average life derived from the entire curve from 100 percent to zero percent surviving. The titles of the chart indicate the group, the symbol used to plot the points of the original life table, and the experience and placement bands of the life tables which where plotted. The experience band indicates the range of years for which retirements were used to develop the stub survivor curve. The placements indicate, for the related experience band, the range of years of installations which appear in the experience.

The analyses of net salvage data are presented in the section titled, “Net Salvage Statistics”. The tabulations present annual cost of removal and salvage data, three-year moving averages and the most recent five-year average. Data are shown in dollars and as percentages of original costs retired.

The tables of the calculated annual depreciation applicable to depreciable assets as of December 31, 2020 are presented in account sequence starting on page IX-2 of the supporting documents. The tables indicate the estimated survivor curve and net salvage percent for the account and set forth, for each installation year, the original cost, the calculated accrued depreciation, the allocated book reserve, future accruals, the remaining life, and the calculated annual accrual amount.

UNITIL ENERGY SYSTEMS, INC.

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2020

	ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST AS OF DECEMBER 31, 2020 (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
	ELECTRIC PLANT								
	PRODUCTION PLANT								
343.00	PRIME MOVERS	10-S3	0	56,575.22	36,796	19,779	10,559	18.66	1.9
	TOTAL PRODUCTION PLANT			**56,575.22**	**36,796**	**19,779**	**10,559**	**18.66**	
	DISTRIBUTION PLANT								
361.00	STRUCTURES AND IMPROVEMENTS	55-R4	(30)	2,173,616.44	306,159	2,519,542	52,132	2.40	48.3
362.00	STATION EQUIPMENT	49-R1.5	(40)	50,412,131.73	10,134,156	60,442,828	1,492,423	2.96	40.5
364.00	POLES, TOWERS AND FIXTURES	50-R1.5	(80)	75,140,860.60	27,977,083	107,276,466	2,709,085	3.61	39.6
365.00	OVERHEAD CONDUCTORS AND DEVICES	45-R0.5	(65)	92,313,722.86	28,941,359	123,376,284	3,343,998	3.62	36.9
366.00	UNDERGROUND CONDUIT	60-R2.5	(25)	2,587,958.32	718,989	2,515,959	55,787	2.16	45.1
367.00	UNDERGROUND CONDUCTORS AND DEVICES	55-R2.5	(50)	23,862,963.47	7,132,135	28,662,310	679,570	2.85	42.2
368.00	LINE TRANSFORMERS	40-R1.5	(10)	29,259,308.24	11,295,662	20,889,577	720,501	2.46	29.0
368.01	LINE TRANSFORMER INSTALLATIONS	40-R1.5	0	25,947,042.32	6,633,459	19,313,583	596,350	2.30	32.4
369.00	SERVICES	40-R2	(50)	25,642,632.28	18,333,473	20,130,475	623,537	2.43	32.3
370.00	METERS	20-R1.5	0	11,764,061.66	5,127,986	6,636,076	1,030,664	8.76	6.4
370.01	METER INSTALLATIONS	20-R1.5	0	7,165,764.75	1,512,910	5,652,855	395,098	5.51	14.3
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES	15-L0	(10)	2,404,367.15	539,998	2,104,806	193,076	8.03	10.9
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	20-L0	(10)	3,580,954.49	3,017,725	921,325	53,416	1.49	17.2
	TOTAL DISTRIBUTION PLANT			**352,255,384.31**	**121,671,094**	**400,442,086**	**11,945,637**	**3.39**	
	GENERAL PLANT								
390.00	STRUCTURES AND IMPROVEMENTS	55-R3	0	19,114,262.13	1,878,592	17,235,670	352,936	1.85	48.8
391.01	OFFICE FURNITURE AND EQUIPMENT								
	FULLY ACCRUED			139,487.40	139,487	0	0	-	-
	AMORTIZED	15-SQ	0	1,150,389.44	137,380	1,013,009	76,687	6.67	13.2
	TOTAL OFFICE FURNITURE AND EQUIPMENT			1,289,876.84	276,867	1,013,009	76,687	5.95	
393.00	STORES EQUIPMENT								
	FULLY ACCRUED			50,899.20	50,899	0	0	-	-
	AMORTIZED	25-SQ	0	39,757.34	19,825	19,932	1,590	4.00	12.5
	TOTAL STORES EQUIPMENT			90,656.54	70,724	19,932	1,590	1.75	
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT								
	FULLY ACCRUED			367,743.18	367,743	0	0	-	-
	AMORTIZED	25-SQ	0	2,062,148.55	730,460	1,331,689	82,572	4.00	16.1
	TOTAL TOOLS, SHOP AND GARAGE EQUIPMENT			2,429,891.73	1,098,203	1,331,689	82,572	3.40	
395.00	LABORATORY EQUIPMENT								
	FULLY ACCRUED			245,174.17	245,174	0	0	-	-
	AMORTIZED	25-SQ	0	703,356.15	254,300	449,056	28,137	4.00	16.0
	TOTAL LABORATORY EQUIPMENT			948,530.32	499,474	449,056	28,137	2.97	

UNITIL ENERGY SYSTEMS, INC.

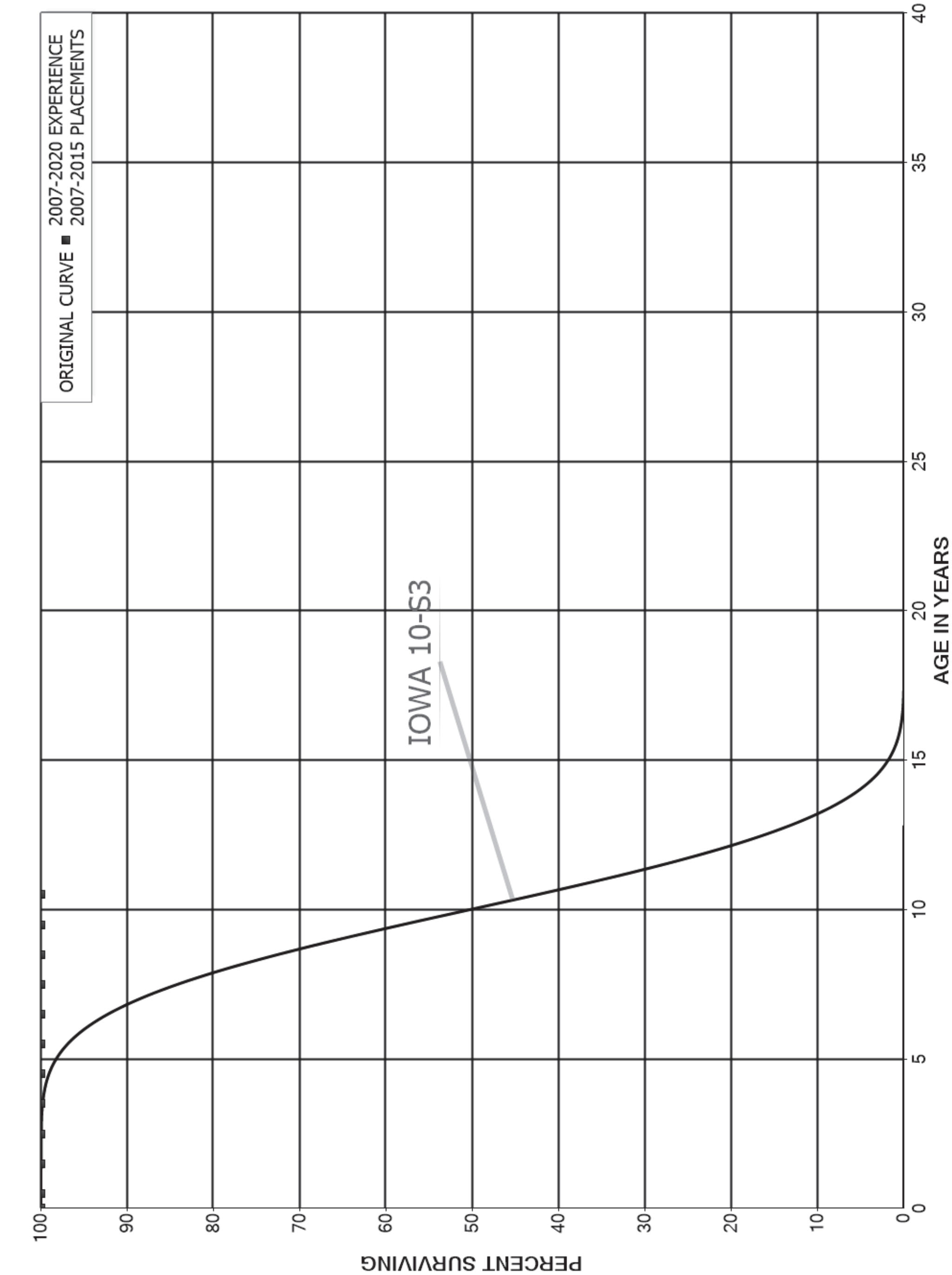
TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2020

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST AS OF DECEMBER 31, 2020	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
397.00	COMMUNICATION EQUIPMENT								
	FULLY ACCRUED			1,747,454.08	1,747,454	0	0	-	-
	AMORTIZED	15-SQ	0	3,258,113.85	1,521,390	1,736,724	217,198	6.67	8.0
	TOTAL COMMUNICATION EQUIPMENT			5,005,567.93	3,268,844	1,736,724	217,198	4.34	
398.00	MISCELLANEOUS EQUIPMENT								
	FULLY ACCRUED			83,715.14	83,715	0	0	-	-
	AMORTIZED	20-SQ	0	19,228.27	16,145	3,083	962	5.00	3.2
	TOTAL MISCELLANEOUS EQUIPMENT			102,943.41	99,860	3,083	962	0.93	
	TOTAL GENERAL PLANT			**28,981,728.90**	**7,192,564**	**21,789,163**	**760,082**	**2.62**	
	RESERVE ADJUSTMENT FOR AMORTIZATION								
390.01	STRUCTURES AND IMPROVEMENTS - MISCELLANEOUS				863		(173) *		
391.01	OFFICE FURNITURE AND EQUIPMENT				(332,958)		66,592 *		
391.03	OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT				4,346		(869) *		
393.00	STORES EQUIPMENT				(4,542)		908 *		
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT				(112,121)		22,424 *		
395.00	LABORATORY EQUIPMENT				(292)		58 *		
397.00	COMMUNICATION EQUIPMENT				8,768		(1,754) *		
398.00	MISCELLANEOUS EQUIPMENT				3,083		(617) *		
	TOTAL RESERVE ADJUSTMENT FOR AMORTIZATION				**(432,853)**		**86,569**		
	TOTAL DEPRECIABLE PLANT			**381,293,688.43**	**128,467,601**	**422,251,028**	**12,802,847**	**3.36**	
	NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED								
301.00	ORGANIZATION			380.00					
303.00	MISCELLANEOUS INTANGIBLE PLANT - 5 YEAR			6,638,390.64	4,743,991				
303.01	MISCELLANEOUS INTANGIBLE PLANT - 3 YEAR			87,195.82	87,196				
303.02	MISCELLANEOUS INTANGIBLE PLANT - 10 YEAR			5,489,895.89	2,700,885				
360.01	RIGHTS OF WAY			1,002,659.97					
360.02	RIGHTS OF WAY			1,674,812.39					
389.00	LAND			1,363,295.15					
392.00	TRANSPORTATION EQUIPMENT			1,073,516.64					
	TOTAL NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED			**17,330,146.50**	**7,532,072**				
	TOTAL ELECTRIC PLANT			**398,623,834.93**	**135,999,673**				

* 5-YEAR AMORTIZATION OF RESERVE ADJUSTMENT RELATED TO IMPLEMENTATION OF AMORTIZATION ACCOUNTING.

PART VII. SERVICE LIFE STATISTICS

UNITIL ENERGY SYSTEMS, INC.
ACCOUNT 343.00 PRIME MOVERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



UNITIL ENERGY SYSTEMS, INC.

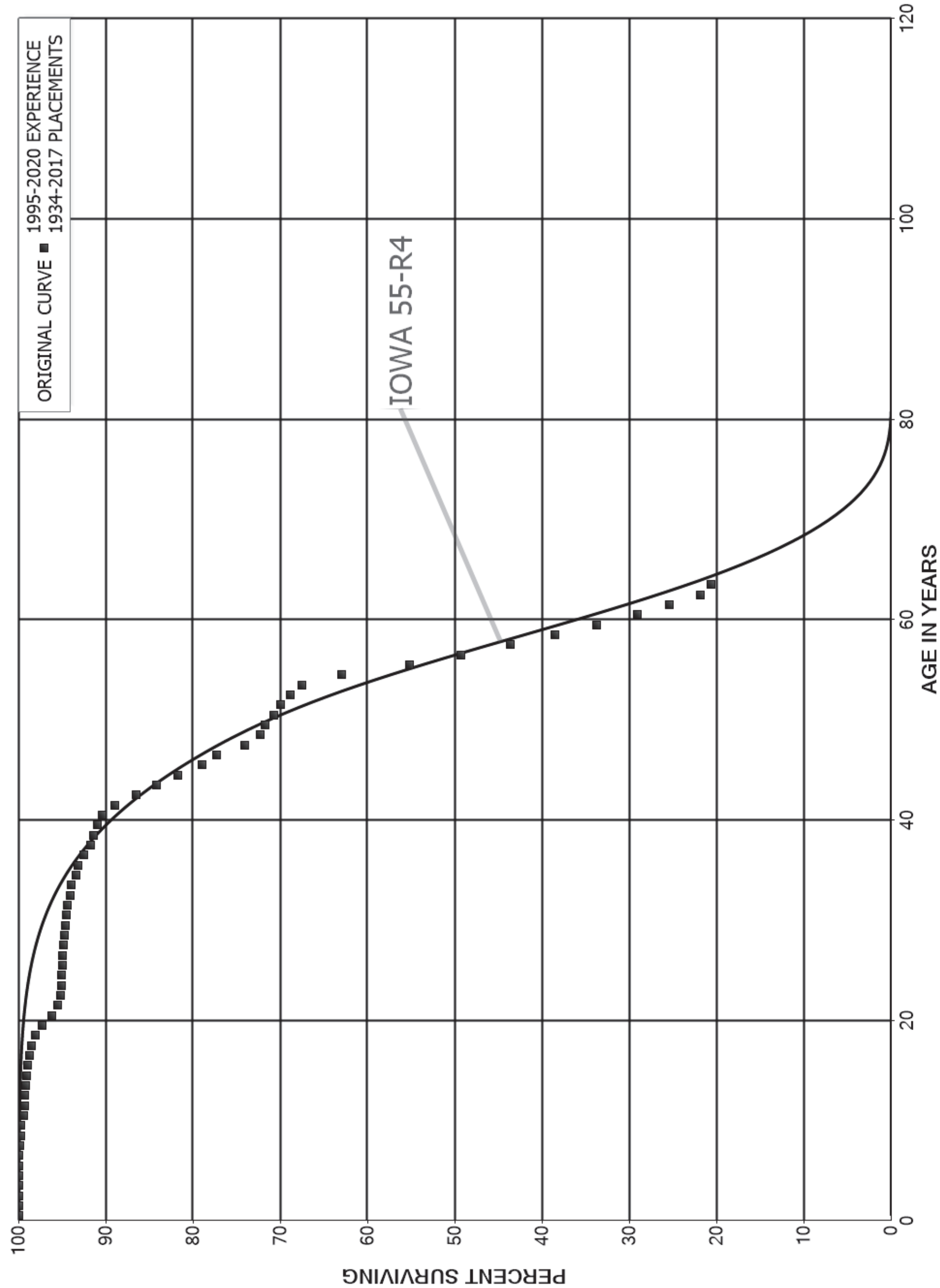
ACCOUNT 343.00 PRIME MOVERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 2007-2015 EXPERIENCE BAND 2007-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	56,575		0.0000	1.0000	100.00
0.5	56,575		0.0000	1.0000	100.00
1.5	56,575		0.0000	1.0000	100.00
2.5	56,575		0.0000	1.0000	100.00
3.5	56,575		0.0000	1.0000	100.00
4.5	56,575		0.0000	1.0000	100.00
5.5	56,372		0.0000	1.0000	100.00
6.5	56,372		0.0000	1.0000	100.00
7.5	56,372		0.0000	1.0000	100.00
8.5	56,372		0.0000	1.0000	100.00
9.5	10,383		0.0000	1.0000	100.00
10.5	10,383		0.0000	1.0000	100.00
11.5	10,383		0.0000	1.0000	100.00
12.5	10,383		0.0000	1.0000	100.00
13.5					100.00

UNITIL ENERGY SYSTEMS, INC.
ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1934-2017 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,073,657	18	0.0000	1.0000	100.00
0.5	2,073,647	4	0.0000	1.0000	100.00
1.5	2,073,642	108	0.0001	0.9999	100.00
2.5	2,073,556	37	0.0000	1.0000	99.99
3.5	984,929	55	0.0001	0.9999	99.99
4.5	67,764	33	0.0005	0.9995	99.99
5.5	68,047	28	0.0004	0.9996	99.94
6.5	68,019	16	0.0002	0.9998	99.90
7.5	68,003	112	0.0016	0.9984	99.87
8.5	67,891	22	0.0003	0.9997	99.71
9.5	67,896	210	0.0031	0.9969	99.68
10.5	67,815	43	0.0006	0.9994	99.37
11.5	67,921	49	0.0007	0.9993	99.31
12.5	72,639	39	0.0005	0.9995	99.23
13.5	78,986	59	0.0007	0.9993	99.18
14.5	102,331	158	0.0015	0.9985	99.11
15.5	114,241	240	0.0021	0.9979	98.95
16.5	116,173	276	0.0024	0.9976	98.75
17.5	111,425	448	0.0040	0.9960	98.51
18.5	74,110	639	0.0086	0.9914	98.12
19.5	73,471	837	0.0114	0.9886	97.27
20.5	72,634	478	0.0066	0.9934	96.16
21.5	72,195	227	0.0031	0.9969	95.53
22.5	71,969	103	0.0014	0.9986	95.23
23.5	55,270	43	0.0008	0.9992	95.09
24.5	57,699	11	0.0002	0.9998	95.02
25.5	57,775	54	0.0009	0.9991	95.00
26.5	61,546	24	0.0004	0.9996	94.91
27.5	63,008	119	0.0019	0.9981	94.88
28.5	78,748	80	0.0010	0.9990	94.70
29.5	79,813	117	0.0015	0.9985	94.60
30.5	79,696	33	0.0004	0.9996	94.46
31.5	81,210	265	0.0033	0.9967	94.42
32.5	82,549	99	0.0012	0.9988	94.12
33.5	82,450	523	0.0063	0.9937	94.00
34.5	82,325	200	0.0024	0.9976	93.41
35.5	82,125	622	0.0076	0.9924	93.18
36.5	82,528	674	0.0082	0.9918	92.47
37.5	85,595	331	0.0039	0.9961	91.72
38.5	82,028	419	0.0051	0.9949	91.36

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1934-2017 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	77,672	442	0.0057	0.9943	90.90
40.5	57,449	938	0.0163	0.9837	90.38
41.5	46,793	1,260	0.0269	0.9731	88.91
42.5	56,477	1,535	0.0272	0.9728	86.51
43.5	56,922	1,678	0.0295	0.9705	84.16
44.5	55,297	1,857	0.0336	0.9664	81.68
45.5	53,609	1,149	0.0214	0.9786	78.94
46.5	52,581	2,195	0.0417	0.9583	77.25
47.5	50,399	1,176	0.0233	0.9767	74.02
48.5	49,234	367	0.0075	0.9925	72.29
49.5	43,315	609	0.0141	0.9859	71.76
50.5	45,250	521	0.0115	0.9885	70.75
51.5	48,178	781	0.0162	0.9838	69.93
52.5	47,794	932	0.0195	0.9805	68.80
53.5	49,526	3,279	0.0662	0.9338	67.46
54.5	34,463	4,263	0.1237	0.8763	62.99
55.5	33,924	3,602	0.1062	0.8938	55.20
56.5	35,536	4,153	0.1169	0.8831	49.34
57.5	34,894	4,035	0.1156	0.8844	43.57
58.5	31,323	3,881	0.1239	0.8761	38.53
59.5	27,443	3,797	0.1384	0.8616	33.76
60.5	28,047	3,518	0.1254	0.8746	29.09
61.5	24,528	3,464	0.1412	0.8588	25.44
62.5	21,064	1,219	0.0579	0.9421	21.85
63.5	17,536	152	0.0087	0.9913	20.58
64.5	17,384	58	0.0033	0.9967	20.40
65.5	17,326	8	0.0005	0.9995	20.34
66.5	16,527		0.0000	1.0000	20.33
67.5	16,527		0.0000	1.0000	20.33
68.5	7,044		0.0000	1.0000	20.33
69.5	6,275		0.0000	1.0000	20.33
70.5	6,222		0.0000	1.0000	20.33
71.5	6,222		0.0000	1.0000	20.33
72.5	6,222		0.0000	1.0000	20.33
73.5	6,222		0.0000	1.0000	20.33
74.5	6,222		0.0000	1.0000	20.33
75.5	6,222		0.0000	1.0000	20.33
76.5	6,222		0.0000	1.0000	20.33
77.5	6,222		0.0000	1.0000	20.33
78.5	6,222		0.0000	1.0000	20.33

UNITIL ENERGY SYSTEMS, INC.

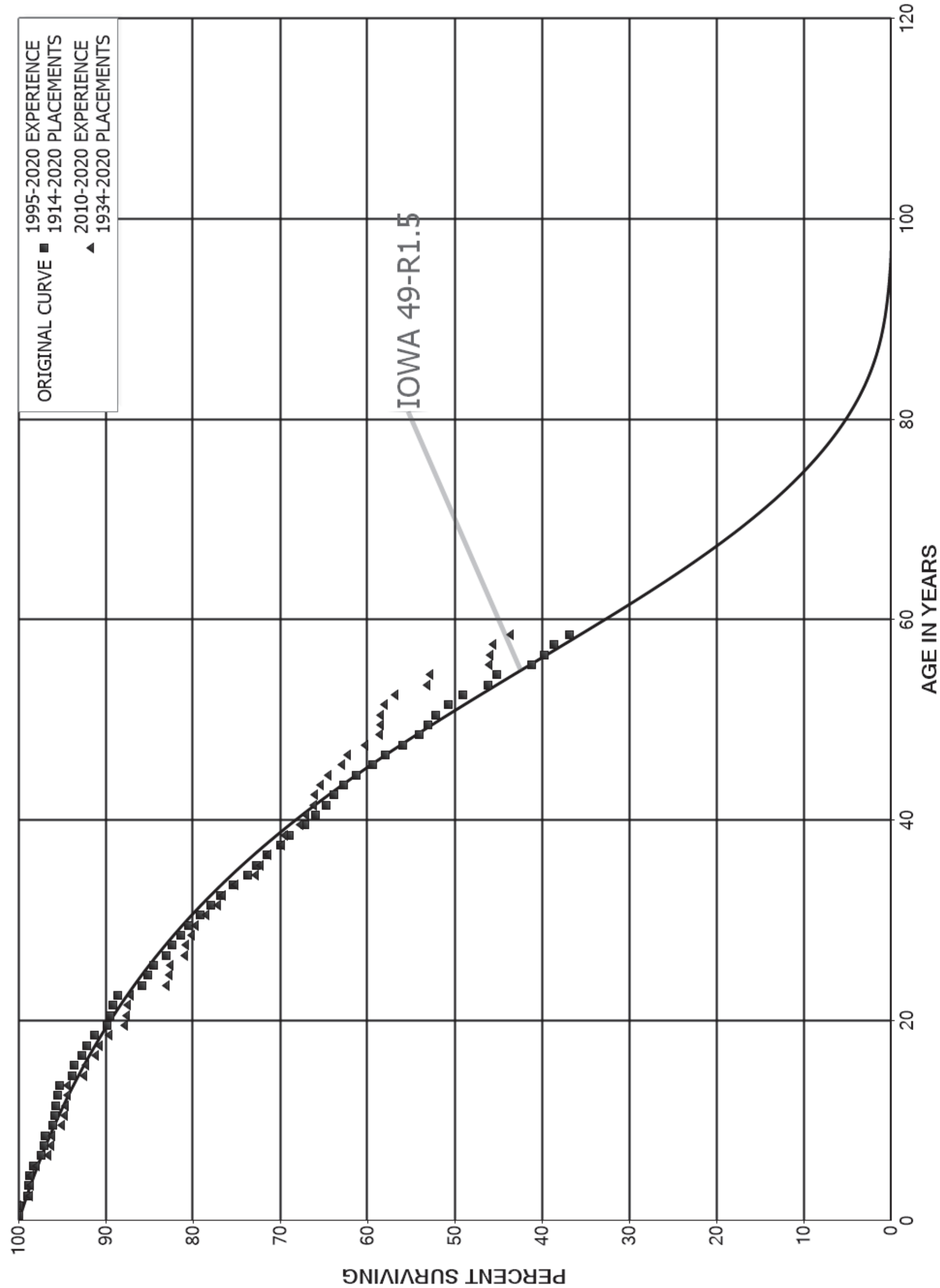
ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1934-2017 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	6,222		0.0000	1.0000	20.33
80.5	6,222		0.0000	1.0000	20.33
81.5	6,059		0.0000	1.0000	20.33
82.5	4,799		0.0000	1.0000	20.33
83.5	4,799		0.0000	1.0000	20.33
84.5	4,799		0.0000	1.0000	20.33
85.5	4,799		0.0000	1.0000	20.33
86.5					20.33

UNITIL ENERGY SYSTEMS, INC.
ACCOUNT 362.00 STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1914-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	46,833,889	18	0.0000	1.0000	100.00
0.5	42,384,257	4,964	0.0001	0.9999	100.00
1.5	41,888,047	450,823	0.0108	0.9892	99.99
2.5	40,894,357	33,698	0.0008	0.9992	98.91
3.5	31,030,137	18,763	0.0006	0.9994	98.83
4.5	19,999,988	89,663	0.0045	0.9955	98.77
5.5	19,724,048	188,197	0.0095	0.9905	98.33
6.5	18,751,631	53,248	0.0028	0.9972	97.39
7.5	16,477,444	23,797	0.0014	0.9986	97.11
8.5	15,854,739	140,102	0.0088	0.9912	96.97
9.5	14,277,332	42,191	0.0030	0.9970	96.12
10.5	13,934,057	20,073	0.0014	0.9986	95.83
11.5	12,371,805	30,134	0.0024	0.9976	95.69
12.5	10,279,069	14,213	0.0014	0.9986	95.46
13.5	9,735,565	147,241	0.0151	0.9849	95.33
14.5	8,564,931	24,019	0.0028	0.9972	93.89
15.5	8,141,344	80,882	0.0099	0.9901	93.62
16.5	7,369,313	38,129	0.0052	0.9948	92.69
17.5	7,028,340	71,182	0.0101	0.9899	92.21
18.5	6,534,483	101,342	0.0155	0.9845	91.28
19.5	6,622,147	27,252	0.0041	0.9959	89.86
20.5	6,639,032	27,709	0.0042	0.9958	89.49
21.5	6,039,725	36,081	0.0060	0.9940	89.12
22.5	6,006,477	185,192	0.0308	0.9692	88.59
23.5	5,378,145	41,958	0.0078	0.9922	85.86
24.5	5,305,117	42,666	0.0080	0.9920	85.19
25.5	5,171,617	85,809	0.0166	0.9834	84.50
26.5	5,038,394	43,282	0.0086	0.9914	83.10
27.5	4,971,987	62,142	0.0125	0.9875	82.39
28.5	4,695,776	49,175	0.0105	0.9895	81.36
29.5	4,374,739	70,263	0.0161	0.9839	80.50
30.5	3,997,482	63,795	0.0160	0.9840	79.21
31.5	3,869,390	55,526	0.0144	0.9856	77.95
32.5	3,849,116	69,290	0.0180	0.9820	76.83
33.5	3,751,476	86,519	0.0231	0.9769	75.45
34.5	3,704,118	51,345	0.0139	0.9861	73.71
35.5	3,614,614	58,429	0.0162	0.9838	72.68
36.5	3,424,962	76,587	0.0224	0.9776	71.51
37.5	3,181,898	41,581	0.0131	0.9869	69.91
38.5	3,065,779	79,605	0.0260	0.9740	69.00

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1914-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,852,490	52,190	0.0183	0.9817	67.21
40.5	2,680,468	51,317	0.0191	0.9809	65.98
41.5	2,598,484	35,392	0.0136	0.9864	64.71
42.5	2,511,988	43,922	0.0175	0.9825	63.83
43.5	2,539,363	57,765	0.0227	0.9773	62.72
44.5	2,495,421	77,915	0.0312	0.9688	61.29
45.5	2,107,889	50,044	0.0237	0.9763	59.37
46.5	1,897,965	67,817	0.0357	0.9643	57.97
47.5	1,753,685	56,226	0.0321	0.9679	55.89
48.5	1,593,448	30,564	0.0192	0.9808	54.10
49.5	1,416,263	24,466	0.0173	0.9827	53.06
50.5	1,241,057	34,437	0.0277	0.9723	52.15
51.5	1,169,470	36,962	0.0316	0.9684	50.70
52.5	959,255	57,544	0.0600	0.9400	49.10
53.5	800,785	17,571	0.0219	0.9781	46.15
54.5	757,372	67,428	0.0890	0.9110	45.14
55.5	628,531	20,677	0.0329	0.9671	41.12
56.5	567,266	15,955	0.0281	0.9719	39.77
57.5	556,440	26,593	0.0478	0.9522	38.65
58.5	486,646	10,210	0.0210	0.9790	36.80
59.5	482,155	21,128	0.0438	0.9562	36.03
60.5	468,522	9,931	0.0212	0.9788	34.45
61.5	414,586	9,684	0.0234	0.9766	33.72
62.5	404,347	9,998	0.0247	0.9753	32.93
63.5	388,287	8,741	0.0225	0.9775	32.12
64.5	382,842	8,954	0.0234	0.9766	31.40
65.5	370,440	7,495	0.0202	0.9798	30.66
66.5	326,898	9,462	0.0289	0.9711	30.04
67.5	303,525	19,907	0.0656	0.9344	29.17
68.5	253,901	7,966	0.0314	0.9686	27.26
69.5	170,676	13,927	0.0816	0.9184	26.40
70.5	124,321	5,840	0.0470	0.9530	24.25
71.5	80,785	4,326	0.0535	0.9465	23.11
72.5	76,390	3,781	0.0495	0.9505	21.87
73.5	73,319	3,815	0.0520	0.9480	20.79
74.5	70,185	2,679	0.0382	0.9618	19.71
75.5	67,733	1,867	0.0276	0.9724	18.96
76.5	66,279	2,216	0.0334	0.9666	18.43
77.5	64,409	1,210	0.0188	0.9812	17.82
78.5	63,435	486	0.0077	0.9923	17.48

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1914-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	49,679	390	0.0079	0.9921	17.35
80.5	45,422	850	0.0187	0.9813	17.21
81.5	41,472	600	0.0145	0.9855	16.89
82.5	25,171	2,322	0.0923	0.9077	16.65
83.5	22,848		0.0000	1.0000	15.11
84.5	22,654	1,616	0.0713	0.9287	15.11
85.5	18,444	6,869	0.3725	0.6275	14.03
86.5					8.81

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	35,150,475		0.0000	1.0000	100.00
0.5	32,280,593	4,674	0.0001	0.9999	100.00
1.5	33,784,973	449,994	0.0133	0.9867	99.99
2.5	33,256,239	31,831	0.0010	0.9990	98.65
3.5	24,233,890	16,118	0.0007	0.9993	98.56
4.5	13,282,164	85,499	0.0064	0.9936	98.49
5.5	13,747,276	183,129	0.0133	0.9867	97.86
6.5	13,248,997	47,255	0.0036	0.9964	96.56
7.5	11,463,344	17,105	0.0015	0.9985	96.21
8.5	11,202,719	132,494	0.0118	0.9882	96.07
9.5	9,731,310	31,551	0.0032	0.9968	94.93
10.5	9,899,862	9,588	0.0010	0.9990	94.62
11.5	8,280,954	17,461	0.0021	0.9979	94.53
12.5	6,765,784	1,994	0.0003	0.9997	94.33
13.5	6,469,036	134,204	0.0207	0.9793	94.31
14.5	5,309,203	8,577	0.0016	0.9984	92.35
15.5	5,065,164	63,413	0.0125	0.9875	92.20
16.5	4,387,019	19,086	0.0044	0.9956	91.05
17.5	4,202,900	53,536	0.0127	0.9873	90.65
18.5	4,053,960	82,438	0.0203	0.9797	89.49
19.5	4,156,660	9,510	0.0023	0.9977	87.67
20.5	4,065,405	6,140	0.0015	0.9985	87.47
21.5	3,424,753	9,613	0.0028	0.9972	87.34
22.5	3,278,940	155,225	0.0473	0.9527	87.10
23.5	2,490,999	10,577	0.0042	0.9958	82.97
24.5	2,302,245	4,643	0.0020	0.9980	82.62
25.5	2,288,774	44,838	0.0196	0.9804	82.45
26.5	2,234,765	1,732	0.0008	0.9992	80.84
27.5	2,151,556	20,170	0.0094	0.9906	80.78
28.5	2,037,060	9,558	0.0047	0.9953	80.02
29.5	1,819,054	28,346	0.0156	0.9844	79.64
30.5	1,515,975	26,314	0.0174	0.9826	78.40
31.5	1,519,074	11,254	0.0074	0.9926	77.04
32.5	1,562,925	29,526	0.0189	0.9811	76.47
33.5	1,525,934	47,872	0.0314	0.9686	75.03
34.5	1,870,679	13,410	0.0072	0.9928	72.67
35.5	1,925,001	23,613	0.0123	0.9877	72.15
36.5	1,843,520	40,333	0.0219	0.9781	71.27
37.5	1,735,719	8,272	0.0048	0.9952	69.71
38.5	1,796,348	44,199	0.0246	0.9754	69.38

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,754,706	18,606	0.0106	0.9894	67.67
40.5	1,602,696	20,275	0.0127	0.9873	66.95
41.5	1,677,293	5,157	0.0031	0.9969	66.10
42.5	1,715,703	15,386	0.0090	0.9910	65.90
43.5	1,644,321	24,305	0.0148	0.9852	65.31
44.5	1,681,638	39,253	0.0233	0.9767	64.34
45.5	1,366,863	13,468	0.0099	0.9901	62.84
46.5	1,200,293	39,688	0.0331	0.9669	62.22
47.5	1,164,497	31,475	0.0270	0.9730	60.17
48.5	1,049,068	2,329	0.0022	0.9978	58.54
49.5	930,067	96	0.0001	0.9999	58.41
50.5	821,426	6,109	0.0074	0.9926	58.40
51.5	781,665	16,375	0.0209	0.9791	57.97
52.5	595,324	38,832	0.0652	0.9348	56.75
53.5	438,356	2,854	0.0065	0.9935	53.05
54.5	400,040	51,498	0.1287	0.8713	52.71
55.5	306,252	328	0.0011	0.9989	45.92
56.5	251,930	2,297	0.0091	0.9909	45.87
57.5	284,526	12,204	0.0429	0.9571	45.45
58.5	297,148	304	0.0010	0.9990	43.51
59.5	331,120	11,228	0.0339	0.9661	43.46
60.5	340,325	298	0.0009	0.9991	41.99
61.5	290,287	66	0.0002	0.9998	41.95
62.5	283,958	129	0.0005	0.9995	41.94
63.5	272,746	14	0.0001	0.9999	41.92
64.5	272,034	581	0.0021	0.9979	41.92
65.5	264,397	23	0.0001	0.9999	41.83
66.5	225,330	1,825	0.0081	0.9919	41.83
67.5	207,004	12,741	0.0615	0.9385	41.49
68.5	176,059	1,422	0.0081	0.9919	38.93
69.5	101,634	8,091	0.0796	0.9204	38.62
70.5	62,844	851	0.0135	0.9865	35.54
71.5	40,664	44	0.0011	0.9989	35.06
72.5	41,934	23	0.0006	0.9994	35.03
73.5	41,961	674	0.0161	0.9839	35.01
74.5	45,578	211	0.0046	0.9954	34.44
75.5	64,182	67	0.0010	0.9990	34.28
76.5	64,090	928	0.0145	0.9855	34.25
77.5	63,162	314	0.0050	0.9950	33.75
78.5	62,813	80	0.0013	0.9987	33.59

UNITIL ENERGY SYSTEMS, INC.

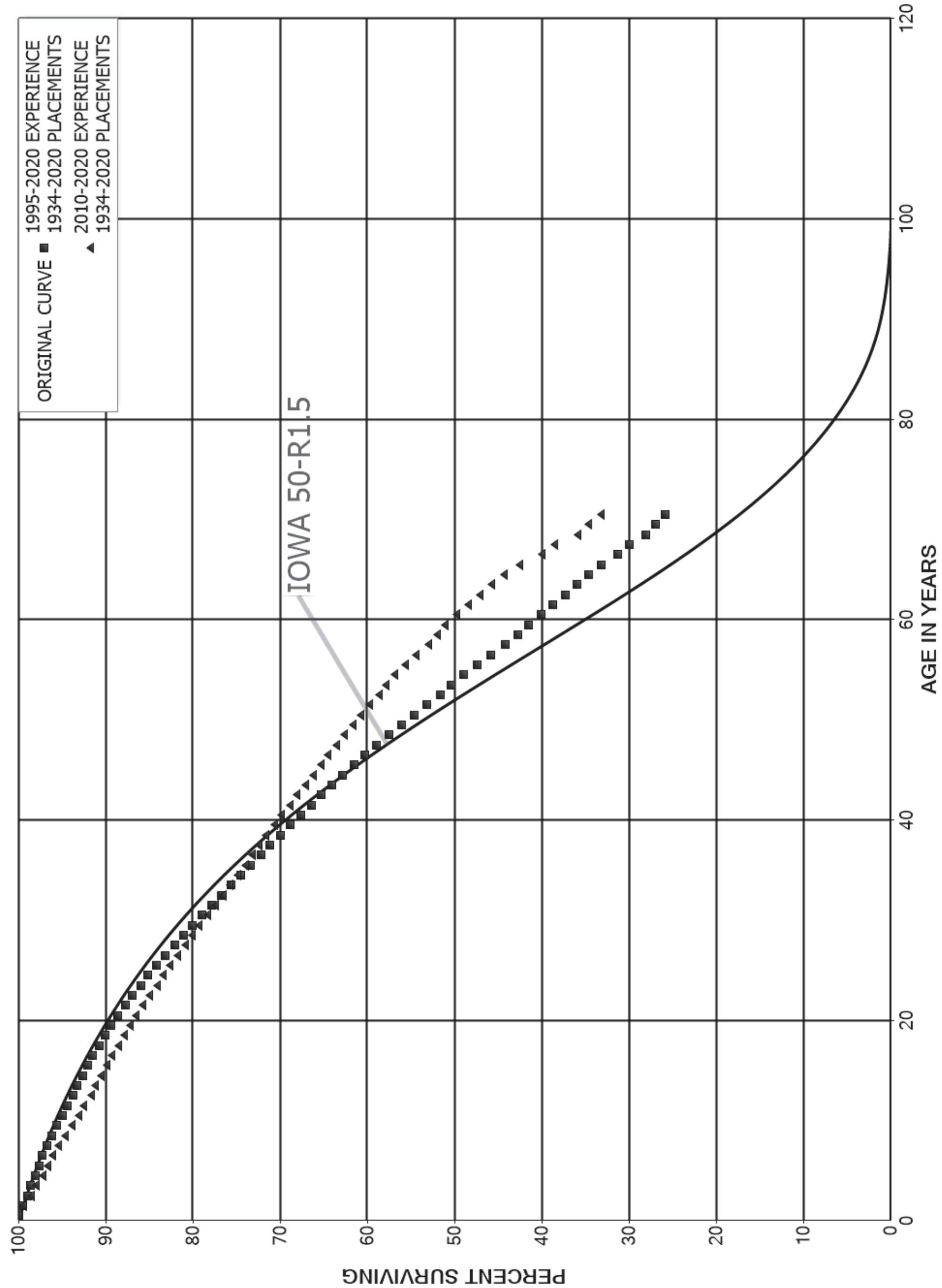
ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	49,243	126	0.0026	0.9974	33.54
80.5	45,088	608	0.0135	0.9865	33.46
81.5	41,379	507	0.0123	0.9877	33.01
82.5	25,171	2,322	0.0923	0.9077	32.60
83.5	22,848		0.0000	1.0000	29.59
84.5	22,654	1,616	0.0713	0.9287	29.59
85.5	18,444	6,869	0.3725	0.6275	27.48
86.5					17.25

UNITIL ENERGY SYSTEMS, INC.
ACCOUNT 364.00 POLES, TOWERS AND FIXTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	66,737,819	54,898	0.0008	0.9992	100.00
0.5	61,439,598	204,419	0.0033	0.9967	99.92
1.5	57,741,223	345,237	0.0060	0.9940	99.59
2.5	53,314,462	217,950	0.0041	0.9959	98.99
3.5	49,115,585	256,588	0.0052	0.9948	98.59
4.5	46,572,029	194,701	0.0042	0.9958	98.07
5.5	43,938,320	184,042	0.0042	0.9958	97.66
6.5	41,439,536	220,241	0.0053	0.9947	97.25
7.5	38,499,814	231,732	0.0060	0.9940	96.73
8.5	35,873,800	209,186	0.0058	0.9942	96.15
9.5	34,383,541	226,109	0.0066	0.9934	95.59
10.5	32,389,820	178,546	0.0055	0.9945	94.96
11.5	30,566,573	220,009	0.0072	0.9928	94.44
12.5	27,864,739	147,206	0.0053	0.9947	93.76
13.5	25,833,064	164,733	0.0064	0.9936	93.26
14.5	23,667,829	153,394	0.0065	0.9935	92.67
15.5	22,491,233	147,562	0.0066	0.9934	92.07
16.5	21,097,905	165,532	0.0078	0.9922	91.46
17.5	18,938,382	142,543	0.0075	0.9925	90.75
18.5	17,833,963	140,410	0.0079	0.9921	90.06
19.5	17,102,360	150,810	0.0088	0.9912	89.36
20.5	16,363,494	147,503	0.0090	0.9910	88.57
21.5	15,326,736	148,681	0.0097	0.9903	87.77
22.5	14,668,566	154,901	0.0106	0.9894	86.92
23.5	13,713,340	139,745	0.0102	0.9898	86.00
24.5	13,082,756	147,601	0.0113	0.9887	85.12
25.5	12,465,902	154,108	0.0124	0.9876	84.16
26.5	11,913,362	145,455	0.0122	0.9878	83.12
27.5	11,244,354	136,443	0.0121	0.9879	82.11
28.5	10,749,074	137,400	0.0128	0.9872	81.11
29.5	10,212,540	147,077	0.0144	0.9856	80.07
30.5	9,597,396	134,775	0.0140	0.9860	78.92
31.5	8,980,046	125,742	0.0140	0.9860	77.81
32.5	8,309,600	115,580	0.0139	0.9861	76.72
33.5	7,619,191	113,890	0.0149	0.9851	75.66
34.5	6,982,343	110,942	0.0159	0.9841	74.53
35.5	6,414,761	99,736	0.0155	0.9845	73.34
36.5	5,877,150	84,962	0.0145	0.9855	72.20
37.5	5,252,283	86,483	0.0165	0.9835	71.16
38.5	4,878,161	84,005	0.0172	0.9828	69.99

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	4,507,176	74,730	0.0166	0.9834	68.78
40.5	4,205,989	74,026	0.0176	0.9824	67.64
41.5	3,837,402	66,051	0.0172	0.9828	66.45
42.5	3,546,543	67,679	0.0191	0.9809	65.31
43.5	3,315,454	63,466	0.0191	0.9809	64.06
44.5	3,026,674	62,245	0.0206	0.9794	62.83
45.5	2,721,438	54,700	0.0201	0.9799	61.54
46.5	2,317,482	53,280	0.0230	0.9770	60.30
47.5	2,082,861	49,719	0.0239	0.9761	58.92
48.5	1,790,867	43,790	0.0245	0.9755	57.51
49.5	1,590,064	41,411	0.0260	0.9740	56.10
50.5	1,411,876	36,907	0.0261	0.9739	54.64
51.5	1,288,693	37,888	0.0294	0.9706	53.22
52.5	1,155,620	28,575	0.0247	0.9753	51.65
53.5	1,027,126	27,957	0.0272	0.9728	50.37
54.5	888,878	28,724	0.0323	0.9677	49.00
55.5	782,496	26,244	0.0335	0.9665	47.42
56.5	695,735	25,662	0.0369	0.9631	45.83
57.5	642,705	20,043	0.0312	0.9688	44.14
58.5	587,617	16,653	0.0283	0.9717	42.76
59.5	513,946	18,000	0.0350	0.9650	41.55
60.5	460,570	15,927	0.0346	0.9654	40.09
61.5	404,659	14,582	0.0360	0.9640	38.71
62.5	341,845	12,194	0.0357	0.9643	37.31
63.5	292,625	10,699	0.0366	0.9634	35.98
64.5	249,561	10,917	0.0437	0.9563	34.67
65.5	212,808	12,068	0.0567	0.9433	33.15
66.5	167,774	6,818	0.0406	0.9594	31.27
67.5	146,976	9,485	0.0645	0.9355	30.00
68.5	121,625	4,671	0.0384	0.9616	28.06
69.5	102,082	4,349	0.0426	0.9574	26.99
70.5	82,603	4,117	0.0498	0.9502	25.84
71.5	64,922	1,955	0.0301	0.9699	24.55
72.5	54,084	1,359	0.0251	0.9749	23.81
73.5	49,715	967	0.0194	0.9806	23.21
74.5	46,751	1,283	0.0274	0.9726	22.76
75.5	44,252	1,628	0.0368	0.9632	22.14
76.5	40,200	885	0.0220	0.9780	21.32
77.5	37,838	627	0.0166	0.9834	20.85
78.5	34,882	870	0.0250	0.9750	20.51

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	32,772	819	0.0250	0.9750	19.99
80.5	29,177	486	0.0167	0.9833	19.49
81.5	28,166	230	0.0082	0.9918	19.17
82.5	26,441	119	0.0045	0.9955	19.01
83.5	13,261	57	0.0043	0.9957	18.93
84.5	8,797	17	0.0020	0.9980	18.85
85.5	8,535	274	0.0321	0.9679	18.81
86.5					18.20

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	41,048,901	54,809	0.0013	0.9987	100.00
0.5	37,730,127	202,958	0.0054	0.9946	99.87
1.5	36,463,888	340,782	0.0093	0.9907	99.33
2.5	33,976,890	209,756	0.0062	0.9938	98.40
3.5	31,752,155	244,703	0.0077	0.9923	97.79
4.5	30,128,134	178,998	0.0059	0.9941	97.04
5.5	28,585,177	163,873	0.0057	0.9943	96.46
6.5	27,752,131	195,760	0.0071	0.9929	95.91
7.5	25,466,496	202,136	0.0079	0.9921	95.23
8.5	23,239,541	175,285	0.0075	0.9925	94.48
9.5	22,291,575	188,375	0.0085	0.9915	93.77
10.5	21,003,324	137,575	0.0066	0.9934	92.97
11.5	19,431,736	174,741	0.0090	0.9910	92.36
12.5	17,485,622	97,974	0.0056	0.9944	91.53
13.5	15,829,166	112,811	0.0071	0.9929	91.02
14.5	13,982,302	97,680	0.0070	0.9930	90.37
15.5	13,031,323	87,559	0.0067	0.9933	89.74
16.5	12,066,728	101,849	0.0084	0.9916	89.14
17.5	10,226,334	74,073	0.0072	0.9928	88.39
18.5	9,413,799	69,350	0.0074	0.9926	87.74
19.5	8,971,811	76,828	0.0086	0.9914	87.10
20.5	8,428,253	71,442	0.0085	0.9915	86.35
21.5	7,875,528	72,191	0.0092	0.9908	85.62
22.5	7,674,805	75,997	0.0099	0.9901	84.84
23.5	7,218,964	59,536	0.0082	0.9918	84.00
24.5	7,040,841	68,142	0.0097	0.9903	83.30
25.5	6,947,278	76,395	0.0110	0.9890	82.50
26.5	6,980,282	71,494	0.0102	0.9898	81.59
27.5	6,642,261	63,049	0.0095	0.9905	80.75
28.5	6,435,424	66,010	0.0103	0.9897	79.99
29.5	6,191,489	77,397	0.0125	0.9875	79.17
30.5	5,911,917	67,878	0.0115	0.9885	78.18
31.5	5,582,155	61,749	0.0111	0.9889	77.28
32.5	5,140,723	53,012	0.0103	0.9897	76.42
33.5	4,701,363	53,413	0.0114	0.9886	75.64
34.5	4,373,469	53,856	0.0123	0.9877	74.78
35.5	4,207,351	46,874	0.0111	0.9889	73.86
36.5	3,868,467	36,766	0.0095	0.9905	73.03
37.5	3,498,182	42,718	0.0122	0.9878	72.34
38.5	3,272,790	42,654	0.0130	0.9870	71.46

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,059,758	36,562	0.0119	0.9881	70.53
40.5	2,827,288	37,218	0.0132	0.9868	69.68
41.5	2,575,328	31,057	0.0121	0.9879	68.77
42.5	2,397,508	34,211	0.0143	0.9857	67.94
43.5	2,272,117	30,007	0.0132	0.9868	66.97
44.5	2,074,291	28,525	0.0138	0.9862	66.08
45.5	1,847,938	22,892	0.0124	0.9876	65.17
46.5	1,503,498	21,878	0.0146	0.9854	64.37
47.5	1,334,283	20,121	0.0151	0.9849	63.43
48.5	1,136,683	16,678	0.0147	0.9853	62.47
49.5	1,015,991	15,861	0.0156	0.9844	61.56
50.5	899,908	14,036	0.0156	0.9844	60.60
51.5	852,788	16,991	0.0199	0.9801	59.65
52.5	779,960	9,536	0.0122	0.9878	58.46
53.5	706,226	11,996	0.0170	0.9830	57.75
54.5	606,628	13,528	0.0223	0.9777	56.77
55.5	550,012	12,405	0.0226	0.9774	55.50
56.5	488,970	13,194	0.0270	0.9730	54.25
57.5	448,318	8,519	0.0190	0.9810	52.78
58.5	418,323	7,107	0.0170	0.9830	51.78
59.5	381,646	9,909	0.0260	0.9740	50.90
60.5	348,924	9,058	0.0260	0.9740	49.58
61.5	312,579	8,898	0.0285	0.9715	48.29
62.5	260,959	7,451	0.0286	0.9714	46.92
63.5	219,630	6,745	0.0307	0.9693	45.58
64.5	182,328	7,236	0.0397	0.9603	44.18
65.5	152,678	9,228	0.0604	0.9396	42.43
66.5	112,926	4,040	0.0358	0.9642	39.86
67.5	98,265	7,050	0.0717	0.9283	38.43
68.5	78,043	2,661	0.0341	0.9659	35.68
69.5	64,581	2,711	0.0420	0.9580	34.46
70.5	47,526	3,008	0.0633	0.9367	33.01
71.5	33,045	1,437	0.0435	0.9565	30.92
72.5	37,869	1,099	0.0290	0.9710	29.58
73.5	38,285	967	0.0252	0.9748	28.72
74.5	35,575	1,283	0.0361	0.9639	28.00
75.5	44,252	1,628	0.0368	0.9632	26.99
76.5	40,200	885	0.0220	0.9780	25.99
77.5	37,838	627	0.0166	0.9834	25.42
78.5	34,882	870	0.0250	0.9750	25.00

UNITIL ENERGY SYSTEMS, INC.

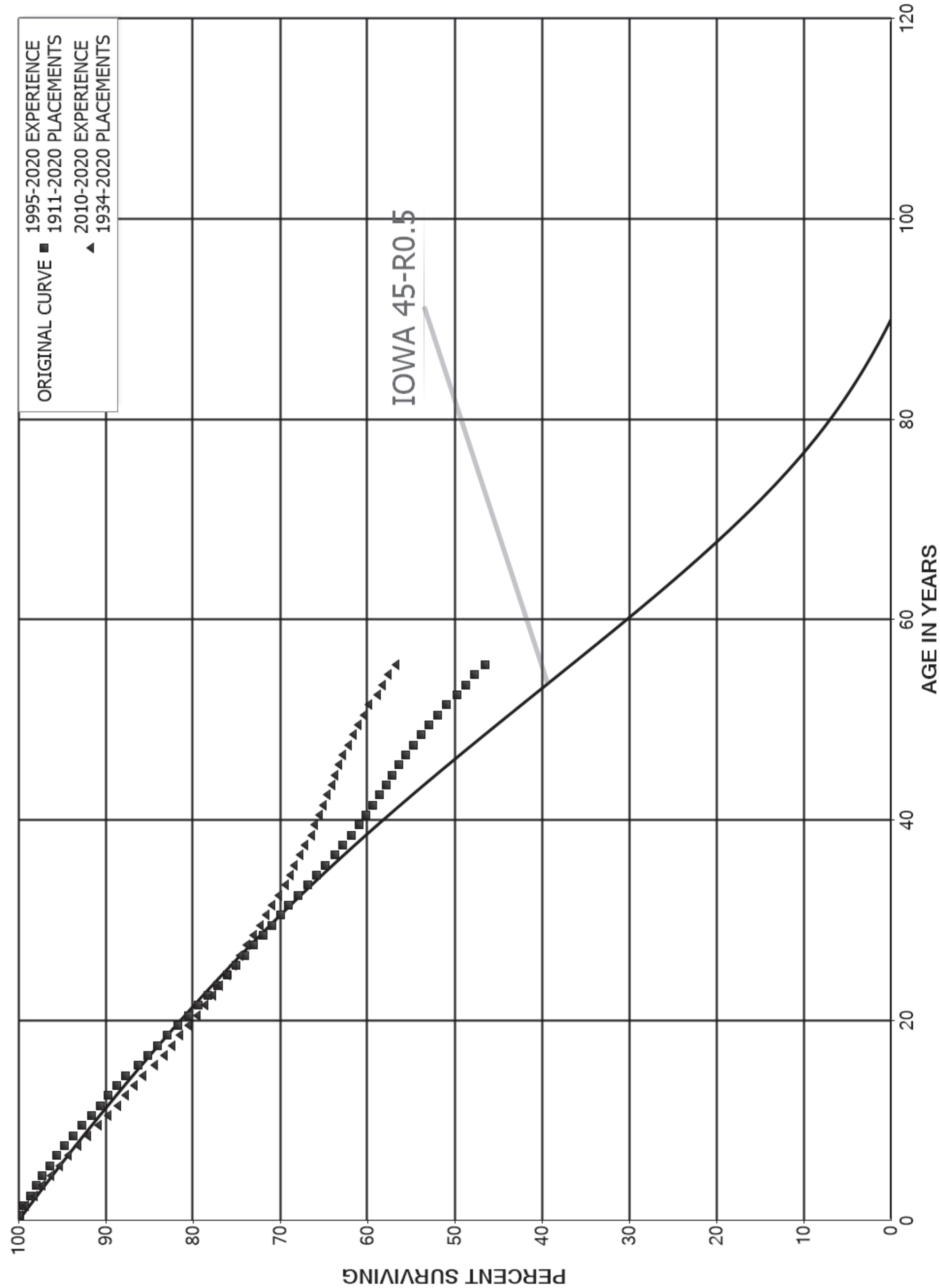
ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	32,772	819	0.0250	0.9750	24.38
80.5	29,177	486	0.0167	0.9833	23.77
81.5	28,166	230	0.0082	0.9918	23.37
82.5	26,441	119	0.0045	0.9955	23.18
83.5	13,261	57	0.0043	0.9957	23.08
84.5	8,797	17	0.0020	0.9980	22.98
85.5	8,535	274	0.0321	0.9679	22.93
86.5					22.19

UNITIL ENERGY SYSTEMS, INC.
ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1911-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	86,901,517	142,656	0.0016	0.9984	100.00
0.5	81,565,575	373,446	0.0046	0.9954	99.84
1.5	77,815,876	564,243	0.0073	0.9927	99.38
2.5	73,972,024	489,923	0.0066	0.9934	98.66
3.5	68,617,900	504,150	0.0073	0.9927	98.00
4.5	65,727,990	564,856	0.0086	0.9914	97.28
5.5	62,487,465	532,649	0.0085	0.9915	96.45
6.5	59,380,276	555,889	0.0094	0.9906	95.63
7.5	54,955,923	577,820	0.0105	0.9895	94.73
8.5	52,057,159	583,750	0.0112	0.9888	93.74
9.5	48,371,551	531,576	0.0110	0.9890	92.68
10.5	45,302,470	503,876	0.0111	0.9889	91.67
11.5	42,311,713	445,748	0.0105	0.9895	90.65
12.5	37,169,268	409,409	0.0110	0.9890	89.69
13.5	33,863,011	394,307	0.0116	0.9884	88.70
14.5	30,421,660	464,159	0.0153	0.9847	87.67
15.5	28,199,910	375,157	0.0133	0.9867	86.33
16.5	25,981,262	329,716	0.0127	0.9873	85.18
17.5	23,094,853	318,527	0.0138	0.9862	84.10
18.5	21,194,629	315,711	0.0149	0.9851	82.94
19.5	19,999,273	290,454	0.0145	0.9855	81.71
20.5	18,824,147	264,247	0.0140	0.9860	80.52
21.5	17,626,027	245,581	0.0139	0.9861	79.39
22.5	16,534,128	234,018	0.0142	0.9858	78.28
23.5	15,082,795	210,423	0.0140	0.9860	77.18
24.5	14,273,127	188,147	0.0132	0.9868	76.10
25.5	13,478,768	181,091	0.0134	0.9866	75.10
26.5	12,805,213	177,410	0.0139	0.9861	74.09
27.5	11,830,920	170,555	0.0144	0.9856	73.06
28.5	11,091,885	157,503	0.0142	0.9858	72.01
29.5	10,474,143	147,095	0.0140	0.9860	70.99
30.5	9,703,269	135,426	0.0140	0.9860	69.99
31.5	8,811,073	137,961	0.0157	0.9843	69.01
32.5	7,987,297	125,521	0.0157	0.9843	67.93
33.5	7,249,626	113,468	0.0157	0.9843	66.86
34.5	6,595,920	96,138	0.0146	0.9854	65.82
35.5	6,017,811	100,479	0.0167	0.9833	64.86
36.5	5,630,065	80,691	0.0143	0.9857	63.77
37.5	5,265,881	89,731	0.0170	0.9830	62.86
38.5	4,947,574	62,911	0.0127	0.9873	61.79

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1911-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	4,672,394	64,926	0.0139	0.9861	61.00
40.5	4,498,639	58,556	0.0130	0.9870	60.16
41.5	4,237,523	50,887	0.0120	0.9880	59.37
42.5	3,976,125	56,777	0.0143	0.9857	58.66
43.5	3,778,000	42,966	0.0114	0.9886	57.82
44.5	3,578,610	44,845	0.0125	0.9875	57.17
45.5	3,295,033	45,803	0.0139	0.9861	56.45
46.5	2,833,512	46,782	0.0165	0.9835	55.66
47.5	2,605,278	44,379	0.0170	0.9830	54.75
48.5	2,263,603	37,199	0.0164	0.9836	53.81
49.5	1,941,136	36,563	0.0188	0.9812	52.93
50.5	1,589,694	30,744	0.0193	0.9807	51.93
51.5	1,452,960	34,634	0.0238	0.9762	50.93
52.5	1,266,797	25,084	0.0198	0.9802	49.71
53.5	1,126,651	23,806	0.0211	0.9789	48.73
54.5	974,115	23,693	0.0243	0.9757	47.70
55.5	867,403	23,614	0.0272	0.9728	46.54
56.5	775,092	16,160	0.0208	0.9792	45.27
57.5	743,289	13,790	0.0186	0.9814	44.33
58.5	680,921	12,008	0.0176	0.9824	43.51
59.5	622,832	11,861	0.0190	0.9810	42.74
60.5	611,682	9,822	0.0161	0.9839	41.92
61.5	566,025	8,021	0.0142	0.9858	41.25
62.5	520,747	7,128	0.0137	0.9863	40.67
63.5	470,261	7,614	0.0162	0.9838	40.11
64.5	432,841	6,968	0.0161	0.9839	39.46
65.5	384,449	6,655	0.0173	0.9827	38.83
66.5	339,897	6,115	0.0180	0.9820	38.15
67.5	290,395	7,323	0.0252	0.9748	37.47
68.5	259,788	5,476	0.0211	0.9789	36.52
69.5	232,691	4,745	0.0204	0.9796	35.75
70.5	206,001	4,814	0.0234	0.9766	35.02
71.5	169,542	3,805	0.0224	0.9776	34.20
72.5	144,881	3,651	0.0252	0.9748	33.44
73.5	124,710	2,324	0.0186	0.9814	32.59
74.5	111,465	2,459	0.0221	0.9779	31.99
75.5	106,861	6,692	0.0626	0.9374	31.28
76.5	99,379	1,908	0.0192	0.9808	29.32
77.5	95,008	1,642	0.0173	0.9827	28.76
78.5	90,818	2,443	0.0269	0.9731	28.26

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1911-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	84,258	1,652	0.0196	0.9804	27.50
80.5	78,599	1,295	0.0165	0.9835	26.96
81.5	73,012	817	0.0112	0.9888	26.52
82.5	68,904	637	0.0092	0.9908	26.22
83.5	50,232	713	0.0142	0.9858	25.98
84.5	47,432	1,240	0.0261	0.9739	25.61
85.5	38,698	729	0.0188	0.9812	24.94
86.5					24.47

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	48,506,067	114,741	0.0024	0.9976	100.00
0.5	45,630,349	314,311	0.0069	0.9931	99.76
1.5	46,284,014	492,461	0.0106	0.9894	99.08
2.5	45,263,975	407,764	0.0090	0.9910	98.02
3.5	43,134,262	414,155	0.0096	0.9904	97.14
4.5	41,823,015	463,262	0.0111	0.9889	96.21
5.5	40,197,324	425,078	0.0106	0.9894	95.14
6.5	39,346,382	439,956	0.0112	0.9888	94.13
7.5	36,340,950	448,747	0.0123	0.9877	93.08
8.5	34,255,006	444,605	0.0130	0.9870	91.93
9.5	31,598,034	388,454	0.0123	0.9877	90.74
10.5	29,655,774	356,036	0.0120	0.9880	89.62
11.5	27,782,539	299,790	0.0108	0.9892	88.55
12.5	24,244,273	264,300	0.0109	0.9891	87.59
13.5	21,827,295	244,654	0.0112	0.9888	86.64
14.5	19,125,397	308,982	0.0162	0.9838	85.67
15.5	17,474,148	222,530	0.0127	0.9873	84.28
16.5	16,140,831	173,808	0.0108	0.9892	83.21
17.5	13,959,672	158,364	0.0113	0.9887	82.31
18.5	12,627,463	155,480	0.0123	0.9877	81.38
19.5	12,029,546	139,366	0.0116	0.9884	80.38
20.5	11,320,624	127,914	0.0113	0.9887	79.45
21.5	10,783,591	120,699	0.0112	0.9888	78.55
22.5	10,139,286	114,761	0.0113	0.9887	77.67
23.5	9,114,600	96,580	0.0106	0.9894	76.79
24.5	8,610,120	81,439	0.0095	0.9905	75.98
25.5	8,132,568	80,313	0.0099	0.9901	75.26
26.5	7,725,418	79,854	0.0103	0.9897	74.51
27.5	6,974,290	74,691	0.0107	0.9893	73.74
28.5	6,456,738	65,318	0.0101	0.9899	72.95
29.5	6,038,735	57,849	0.0096	0.9904	72.22
30.5	5,526,096	49,123	0.0089	0.9911	71.52
31.5	4,922,974	56,799	0.0115	0.9885	70.89
32.5	4,295,125	45,520	0.0106	0.9894	70.07
33.5	3,767,143	35,433	0.0094	0.9906	69.33
34.5	3,414,938	22,134	0.0065	0.9935	68.68
35.5	3,313,591	32,264	0.0097	0.9903	68.23
36.5	3,155,687	21,150	0.0067	0.9933	67.57
37.5	3,109,664	38,852	0.0125	0.9875	67.11
38.5	3,080,009	17,511	0.0057	0.9943	66.28

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,128,202	24,704	0.0079	0.9921	65.90
40.5	3,023,331	21,826	0.0072	0.9928	65.38
41.5	2,900,141	17,617	0.0061	0.9939	64.91
42.5	2,762,234	26,459	0.0096	0.9904	64.51
43.5	2,688,099	14,017	0.0052	0.9948	63.89
44.5	2,592,403	15,882	0.0061	0.9939	63.56
45.5	2,387,866	16,812	0.0070	0.9930	63.17
46.5	1,967,974	19,475	0.0099	0.9901	62.73
47.5	1,802,397	18,533	0.0103	0.9897	62.11
48.5	1,533,868	11,595	0.0076	0.9924	61.47
49.5	1,289,668	14,601	0.0113	0.9887	61.00
50.5	1,000,865	10,393	0.0104	0.9896	60.31
51.5	924,820	15,018	0.0162	0.9838	59.69
52.5	803,515	7,612	0.0095	0.9905	58.72
53.5	712,399	7,410	0.0104	0.9896	58.16
54.5	613,616	9,767	0.0159	0.9841	57.56
55.5	556,994	12,425	0.0223	0.9777	56.64
56.5	513,783	5,828	0.0113	0.9887	55.38
57.5	493,784	4,995	0.0101	0.9899	54.75
58.5	459,003	4,810	0.0105	0.9895	54.19
59.5	424,607	5,651	0.0133	0.9867	53.63
60.5	404,543	4,430	0.0110	0.9890	52.91
61.5	385,085	3,708	0.0096	0.9904	52.33
62.5	360,838	3,242	0.0090	0.9910	51.83
63.5	326,626	3,575	0.0109	0.9891	51.36
64.5	294,460	3,097	0.0105	0.9895	50.80
65.5	250,001	2,847	0.0114	0.9886	50.27
66.5	212,419	2,290	0.0108	0.9892	49.69
67.5	169,069	3,582	0.0212	0.9788	49.16
68.5	146,323	1,837	0.0126	0.9874	48.12
69.5	127,300	1,515	0.0119	0.9881	47.51
70.5	108,991	2,126	0.0195	0.9805	46.95
71.5	78,618	1,575	0.0200	0.9800	46.03
72.5	76,605	1,803	0.0235	0.9765	45.11
73.5	60,361	687	0.0114	0.9886	44.05
74.5	56,803	1,201	0.0211	0.9789	43.55
75.5	101,064	5,652	0.0559	0.9441	42.63
76.5	94,442	1,050	0.0111	0.9889	40.24
77.5	90,787	939	0.0103	0.9897	39.79
78.5	87,188	1,866	0.0214	0.9786	39.38

UNITIL ENERGY SYSTEMS, INC.

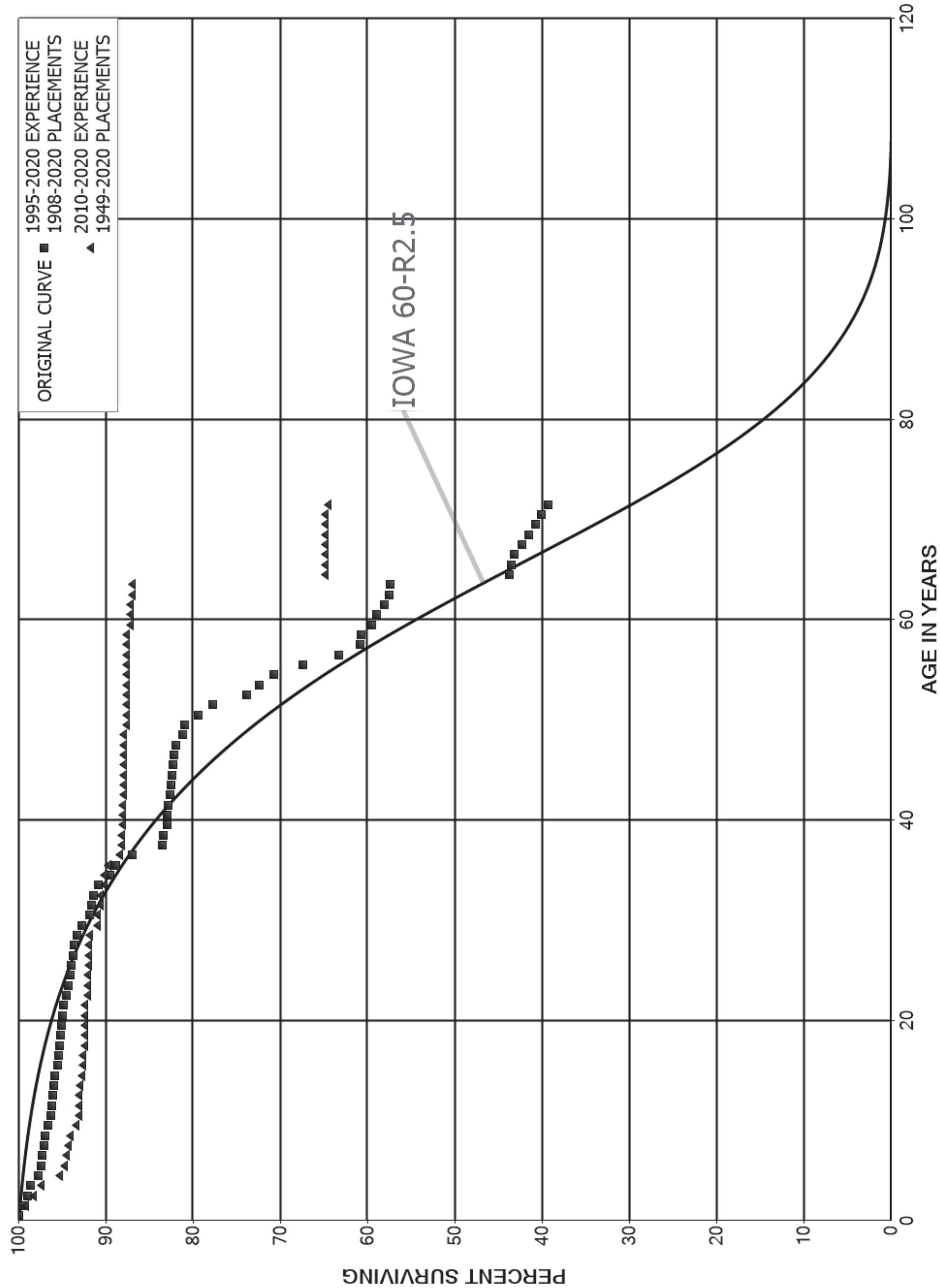
ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	81,096	1,176	0.0145	0.9855	38.54
80.5	75,847	878	0.0116	0.9884	37.98
81.5	70,591	485	0.0069	0.9931	37.54
82.5	66,777	264	0.0040	0.9960	37.28
83.5	48,476	200	0.0041	0.9959	37.14
84.5	46,189	213	0.0046	0.9954	36.98
85.5	38,482	512	0.0133	0.9867	36.81
86.5					36.32

UNITIL ENERGY SYSTEMS, INC.
ACCOUNT 366.00 UNDERGROUND CONDUIT
ORIGINAL AND SMOOTH SURVIVOR CURVES



UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 366.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1908-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,070,514	1,059	0.0005	0.9995	100.00
0.5	1,721,820	8,226	0.0048	0.9952	99.95
1.5	1,687,254	8,040	0.0048	0.9952	99.47
2.5	1,555,645	5,988	0.0038	0.9962	99.00
3.5	1,484,956	13,773	0.0093	0.9907	98.62
4.5	1,455,363	4,526	0.0031	0.9969	97.70
5.5	1,318,381	1,856	0.0014	0.9986	97.40
6.5	1,280,085	2,436	0.0019	0.9981	97.26
7.5	1,227,268	2,062	0.0017	0.9983	97.08
8.5	1,213,881	4,240	0.0035	0.9965	96.91
9.5	1,259,087	3,083	0.0024	0.9976	96.57
10.5	1,216,777	2,483	0.0020	0.9980	96.34
11.5	1,156,926	1,064	0.0009	0.9991	96.14
12.5	1,162,580	1,495	0.0013	0.9987	96.05
13.5	1,144,925	1,733	0.0015	0.9985	95.93
14.5	1,103,310	2,952	0.0027	0.9973	95.78
15.5	1,018,357	1,115	0.0011	0.9989	95.53
16.5	946,417	1,610	0.0017	0.9983	95.42
17.5	931,987	927	0.0010	0.9990	95.26
18.5	898,053	1,183	0.0013	0.9987	95.17
19.5	851,859	1,317	0.0015	0.9985	95.04
20.5	871,577	909	0.0010	0.9990	94.89
21.5	819,268	2,350	0.0029	0.9971	94.79
22.5	816,860	1,899	0.0023	0.9977	94.52
23.5	749,711	1,485	0.0020	0.9980	94.30
24.5	689,204	1,260	0.0018	0.9982	94.12
25.5	607,932	1,323	0.0022	0.9978	93.94
26.5	592,261	845	0.0014	0.9986	93.74
27.5	505,549	1,521	0.0030	0.9970	93.61
28.5	457,689	2,909	0.0064	0.9936	93.32
29.5	446,410	4,050	0.0091	0.9909	92.73
30.5	427,210	1,216	0.0028	0.9972	91.89
31.5	417,798	1,211	0.0029	0.9971	91.63
32.5	402,238	2,515	0.0063	0.9937	91.36
33.5	366,236	5,351	0.0146	0.9854	90.79
34.5	335,368	2,321	0.0069	0.9931	89.46
35.5	279,114	5,849	0.0210	0.9790	88.85
36.5	245,359	9,850	0.0401	0.9599	86.98
37.5	232,589	218	0.0009	0.9991	83.49
38.5	232,235	1,184	0.0051	0.9949	83.41

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 366.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1908-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	230,009	240	0.0010	0.9990	82.99
40.5	224,270	135	0.0006	0.9994	82.90
41.5	222,075	560	0.0025	0.9975	82.85
42.5	219,148	381	0.0017	0.9983	82.64
43.5	166,868	311	0.0019	0.9981	82.50
44.5	165,506	138	0.0008	0.9992	82.35
45.5	166,505	234	0.0014	0.9986	82.28
46.5	113,362	294	0.0026	0.9974	82.16
47.5	111,320	995	0.0089	0.9911	81.95
48.5	82,681	314	0.0038	0.9962	81.22
49.5	21,528	394	0.0183	0.9817	80.91
50.5	20,938	438	0.0209	0.9791	79.42
51.5	20,504	1,040	0.0507	0.9493	77.76
52.5	19,483	390	0.0200	0.9800	73.82
53.5	19,212	441	0.0230	0.9770	72.34
54.5	17,725	829	0.0468	0.9532	70.68
55.5	16,997	1,025	0.0603	0.9397	67.37
56.5	16,066	640	0.0399	0.9601	63.31
57.5	15,512	27	0.0018	0.9982	60.79
58.5	15,564	314	0.0202	0.9798	60.68
59.5	15,322	126	0.0082	0.9918	59.45
60.5	15,263	248	0.0162	0.9838	58.97
61.5	15,075	133	0.0088	0.9912	58.01
62.5	11,953	20	0.0017	0.9983	57.50
63.5	11,982	2,864	0.2390	0.7610	57.40
64.5	5,872	27	0.0046	0.9954	43.68
65.5	5,886	38	0.0064	0.9936	43.48
66.5	5,559	116	0.0209	0.9791	43.20
67.5	5,474	104	0.0190	0.9810	42.30
68.5	5,399	96	0.0177	0.9823	41.49
69.5	5,328	88	0.0166	0.9834	40.76
70.5	5,262	102	0.0194	0.9806	40.08
71.5	515	73	0.1417	0.8583	39.31
72.5	459	66	0.1437	0.8563	33.74
73.5	408	60	0.1463	0.8537	28.89
74.5	361	54	0.1494	0.8506	24.66
75.5	342	49	0.1423	0.8577	20.98
76.5	323	44	0.1353	0.8647	17.99
77.5	304	41	0.1362	0.8638	15.56
78.5	284	37	0.1311	0.8689	13.44

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 366.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1908-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	264	35	0.1327	0.8673	11.68
80.5	243	31	0.1268	0.8732	10.13
81.5	224	27	0.1219	0.8781	8.84
82.5	206	24	0.1153	0.8847	7.76
83.5	190	22	0.1140	0.8860	6.87
84.5	174	20	0.1135	0.8865	6.09
85.5	159	17	0.1064	0.8936	5.40
86.5	145	18	0.1238	0.8762	4.82
87.5	127	16	0.1241	0.8759	4.22
88.5	111	26	0.2295	0.7705	3.70
89.5	86	20	0.2359	0.7641	2.85
90.5	66	16	0.2512	0.7488	2.18
91.5	49	13	0.2668	0.7332	1.63
92.5	36	11	0.2946	0.7054	1.20
93.5	25	9	0.3577	0.6423	0.84
94.5	16	9	0.5221	0.4779	0.54
95.5	8	5	0.6000	0.4000	0.26
96.5	3	2	0.7596	0.2404	0.10
97.5	1	1	1.0000		0.02
98.5					

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 366.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1949-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,187,541	751	0.0006	0.9994	100.00
0.5	889,806	7,503	0.0084	0.9916	99.94
1.5	773,539	7,317	0.0095	0.9905	99.09
2.5	616,083	5,365	0.0087	0.9913	98.16
3.5	585,575	12,941	0.0221	0.9779	97.30
4.5	626,873	3,893	0.0062	0.9938	95.15
5.5	562,045	999	0.0018	0.9982	94.56
6.5	576,556	1,611	0.0028	0.9972	94.39
7.5	526,265	1,274	0.0024	0.9976	94.13
8.5	535,267	3,242	0.0061	0.9939	93.90
9.5	564,274	2,060	0.0036	0.9964	93.33
10.5	543,952	541	0.0010	0.9990	92.99
11.5	513,111		0.0000	1.0000	92.90
12.5	651,326	771	0.0012	0.9988	92.90
13.5	691,885	977	0.0014	0.9986	92.79
14.5	725,677	1,438	0.0020	0.9980	92.66
15.5	652,888	146	0.0002	0.9998	92.47
16.5	659,554	942	0.0014	0.9986	92.45
17.5	640,413	228	0.0004	0.9996	92.32
18.5	614,420	204	0.0003	0.9997	92.29
19.5	579,422		0.0000	1.0000	92.26
20.5	548,556		0.0000	1.0000	92.26
21.5	508,691	1,691	0.0033	0.9967	92.26
22.5	508,711	166	0.0003	0.9997	91.95
23.5	398,212	26	0.0001	0.9999	91.92
24.5	393,486	244	0.0006	0.9994	91.92
25.5	343,727	52	0.0002	0.9998	91.86
26.5	334,615	102	0.0003	0.9997	91.84
27.5	256,831	120	0.0005	0.9995	91.82
28.5	211,511	2,067	0.0098	0.9902	91.77
29.5	207,191	132	0.0006	0.9994	90.88
30.5	195,204	743	0.0038	0.9962	90.82
31.5	189,658	12	0.0001	0.9999	90.47
32.5	228,168	1,000	0.0044	0.9956	90.47
33.5	194,537	60	0.0003	0.9997	90.07
34.5	171,736	854	0.0050	0.9950	90.04
35.5	170,129	2,438	0.0143	0.9857	89.60
36.5	138,844	378	0.0027	0.9973	88.31
37.5	162,838	4	0.0000	1.0000	88.07
38.5	216,255	157	0.0007	0.9993	88.07

UNITIL ENERGY SYSTEMS, INC.

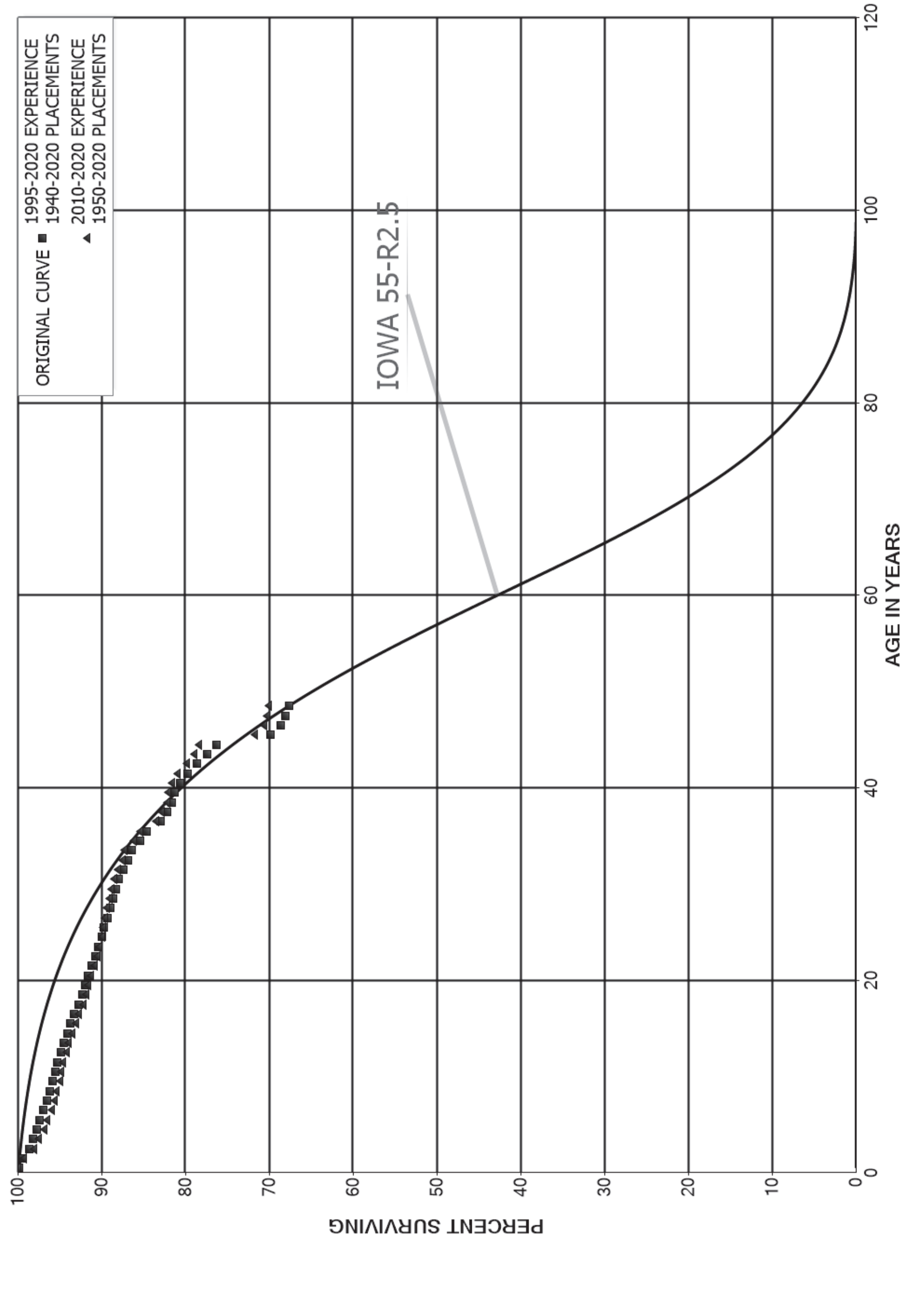
ACCOUNT 366.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1949-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	214,861	18	0.0001	0.9999	88.00
40.5	208,557	16	0.0001	0.9999	88.00
41.5	205,459	341	0.0017	0.9983	87.99
42.5	201,666	139	0.0007	0.9993	87.84
43.5	150,101		0.0000	1.0000	87.78
44.5	149,044	2	0.0000	1.0000	87.78
45.5	145,214	3	0.0000	1.0000	87.78
46.5	92,177		0.0000	1.0000	87.78
47.5	90,144		0.0000	1.0000	87.78
48.5	62,390	184	0.0029	0.9971	87.78
49.5	1,362		0.0000	1.0000	87.52
50.5	1,156		0.0000	1.0000	87.52
51.5	4,200		0.0000	1.0000	87.52
52.5	4,200		0.0000	1.0000	87.52
53.5	10,413		0.0000	1.0000	87.52
54.5	9,258		0.0000	1.0000	87.52
55.5	9,582		0.0000	1.0000	87.52
56.5	9,582	1	0.0001	0.9999	87.52
57.5	9,581		0.0000	1.0000	87.51
58.5	9,581	53	0.0055	0.9945	87.51
59.5	9,528		0.0000	1.0000	87.02
60.5	14,219		0.0000	1.0000	87.02
61.5	14,219	28	0.0020	0.9980	87.02
62.5	11,146		0.0000	1.0000	86.85
63.5	11,146	2,840	0.2548	0.7452	86.85
64.5	5,016		0.0000	1.0000	64.72
65.5	5,016		0.0000	1.0000	64.72
66.5	4,691	3	0.0007	0.9993	64.72
67.5	4,688		0.0000	1.0000	64.68
68.5	4,688		0.0000	1.0000	64.68
69.5	4,688	1	0.0001	0.9999	64.68
70.5	4,687	22	0.0047	0.9953	64.67
71.5					64.37

UNITIL ENERGY SYSTEMS, INC.
ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1940-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	22,084,658	33,039	0.0015	0.9985	100.00
0.5	21,711,813	108,204	0.0050	0.9950	99.85
1.5	20,088,364	144,891	0.0072	0.9928	99.35
2.5	18,607,741	85,109	0.0046	0.9954	98.64
3.5	17,403,341	83,436	0.0048	0.9952	98.19
4.5	16,796,351	56,245	0.0033	0.9967	97.71
5.5	15,609,482	72,924	0.0047	0.9953	97.39
6.5	15,146,522	63,470	0.0042	0.9958	96.93
7.5	14,785,088	45,614	0.0031	0.9969	96.53
8.5	14,513,351	60,640	0.0042	0.9958	96.23
9.5	14,406,181	42,873	0.0030	0.9970	95.83
10.5	14,089,175	37,771	0.0027	0.9973	95.54
11.5	13,303,695	55,279	0.0042	0.9958	95.28
12.5	12,530,787	43,711	0.0035	0.9965	94.89
13.5	11,789,275	56,634	0.0048	0.9952	94.56
14.5	10,958,069	48,527	0.0044	0.9956	94.10
15.5	9,777,116	45,103	0.0046	0.9954	93.69
16.5	8,495,575	46,990	0.0055	0.9945	93.25
17.5	7,620,937	33,450	0.0044	0.9956	92.74
18.5	6,834,487	24,077	0.0035	0.9965	92.33
19.5	6,056,656	26,397	0.0044	0.9956	92.01
20.5	5,369,056	27,044	0.0050	0.9950	91.61
21.5	4,744,451	21,181	0.0045	0.9955	91.14
22.5	4,243,765	15,902	0.0037	0.9963	90.74
23.5	3,751,148	16,352	0.0044	0.9956	90.40
24.5	3,390,908	11,769	0.0035	0.9965	90.00
25.5	2,916,364	13,108	0.0045	0.9955	89.69
26.5	2,545,565	7,938	0.0031	0.9969	89.29
27.5	2,313,521	10,601	0.0046	0.9954	89.01
28.5	2,150,658	7,278	0.0034	0.9966	88.60
29.5	2,044,659	9,019	0.0044	0.9956	88.30
30.5	1,827,340	9,733	0.0053	0.9947	87.91
31.5	1,607,520	11,544	0.0072	0.9928	87.44
32.5	1,333,874	5,777	0.0043	0.9957	86.82
33.5	992,476	11,402	0.0115	0.9885	86.44
34.5	726,877	6,804	0.0094	0.9906	85.45
35.5	573,731	11,847	0.0206	0.9794	84.65
36.5	466,991	4,024	0.0086	0.9914	82.90
37.5	445,421	3,293	0.0074	0.9926	82.18
38.5	402,188	1,240	0.0031	0.9969	81.58

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1940-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	365,341	3,060	0.0084	0.9916	81.33
40.5	340,910	3,756	0.0110	0.9890	80.64
41.5	287,934	4,209	0.0146	0.9854	79.76
42.5	253,789	3,990	0.0157	0.9843	78.59
43.5	216,023	3,015	0.0140	0.9860	77.35
44.5	197,710	16,777	0.0849	0.9151	76.28
45.5	163,933	2,726	0.0166	0.9834	69.80
46.5	134,945	1,069	0.0079	0.9921	68.64
47.5	120,626	760	0.0063	0.9937	68.10
48.5	95,218	602	0.0063	0.9937	67.67
49.5	22,853	416	0.0182	0.9818	67.24
50.5	16,488	331	0.0201	0.9799	66.02
51.5	16,192	204	0.0126	0.9874	64.69
52.5	16,080	196	0.0122	0.9878	63.88
53.5	15,744	259	0.0164	0.9836	63.10
54.5	12,083	230	0.0190	0.9810	62.06
55.5	11,854	184	0.0155	0.9845	60.88
56.5	11,669	41	0.0035	0.9965	59.94
57.5	11,301	25	0.0023	0.9977	59.73
58.5	9,624	27	0.0028	0.9972	59.59
59.5	9,597	25	0.0026	0.9974	59.43
60.5	8,772	24	0.0027	0.9973	59.27
61.5	8,748	15	0.0017	0.9983	59.11
62.5	5,058	12	0.0023	0.9977	59.01
63.5	5,047		0.0000	1.0000	58.87
64.5	1,322		0.0000	1.0000	58.87
65.5	1,322		0.0000	1.0000	58.87
66.5	1,322		0.0000	1.0000	58.87
67.5	1,322		0.0000	1.0000	58.87
68.5	1,322		0.0000	1.0000	58.87
69.5	63		0.0000	1.0000	58.87
70.5					58.87

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1950-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	10,155,558	15,287	0.0015	0.9985	100.00
0.5	10,200,892	70,963	0.0070	0.9930	99.85
1.5	9,178,343	108,410	0.0118	0.9882	99.15
2.5	8,329,717	51,549	0.0062	0.9938	97.98
3.5	7,888,751	53,739	0.0068	0.9932	97.38
4.5	8,334,013	27,851	0.0033	0.9967	96.71
5.5	8,245,043	46,141	0.0056	0.9944	96.39
6.5	8,419,341	34,921	0.0041	0.9959	95.85
7.5	8,529,085	17,601	0.0021	0.9979	95.45
8.5	8,828,871	34,474	0.0039	0.9961	95.26
9.5	9,320,358	20,696	0.0022	0.9978	94.88
10.5	9,536,857	18,195	0.0019	0.9981	94.67
11.5	9,286,527	37,575	0.0040	0.9960	94.49
12.5	9,075,772	27,654	0.0030	0.9970	94.11
13.5	8,670,684	42,616	0.0049	0.9951	93.82
14.5	8,303,939	35,184	0.0042	0.9958	93.36
15.5	7,430,130	32,175	0.0043	0.9957	92.97
16.5	6,348,720	33,961	0.0053	0.9947	92.57
17.5	5,605,786	20,553	0.0037	0.9963	92.07
18.5	4,913,412	11,910	0.0024	0.9976	91.73
19.5	4,313,581	16,658	0.0039	0.9961	91.51
20.5	3,814,429	17,904	0.0047	0.9953	91.16
21.5	3,456,746	12,542	0.0036	0.9964	90.73
22.5	3,278,138	9,554	0.0029	0.9971	90.40
23.5	2,969,490	10,449	0.0035	0.9965	90.14
24.5	2,764,278	4,276	0.0015	0.9985	89.82
25.5	2,399,620	6,100	0.0025	0.9975	89.68
26.5	2,055,723	4,291	0.0021	0.9979	89.45
27.5	1,878,016	6,854	0.0036	0.9964	89.27
28.5	1,754,853	3,642	0.0021	0.9979	88.94
29.5	1,676,074	5,923	0.0035	0.9965	88.76
30.5	1,525,862	7,449	0.0049	0.9951	88.44
31.5	1,343,564	8,766	0.0065	0.9935	88.01
32.5	1,110,556	3,653	0.0033	0.9967	87.44
33.5	789,532	9,792	0.0124	0.9876	87.15
34.5	560,179	4,801	0.0086	0.9914	86.07
35.5	441,732	9,988	0.0226	0.9774	85.33
36.5	347,278	2,866	0.0083	0.9917	83.40
37.5	352,356	2,584	0.0073	0.9927	82.71
38.5	377,986	518	0.0014	0.9986	82.10

UNITIL ENERGY SYSTEMS, INC.

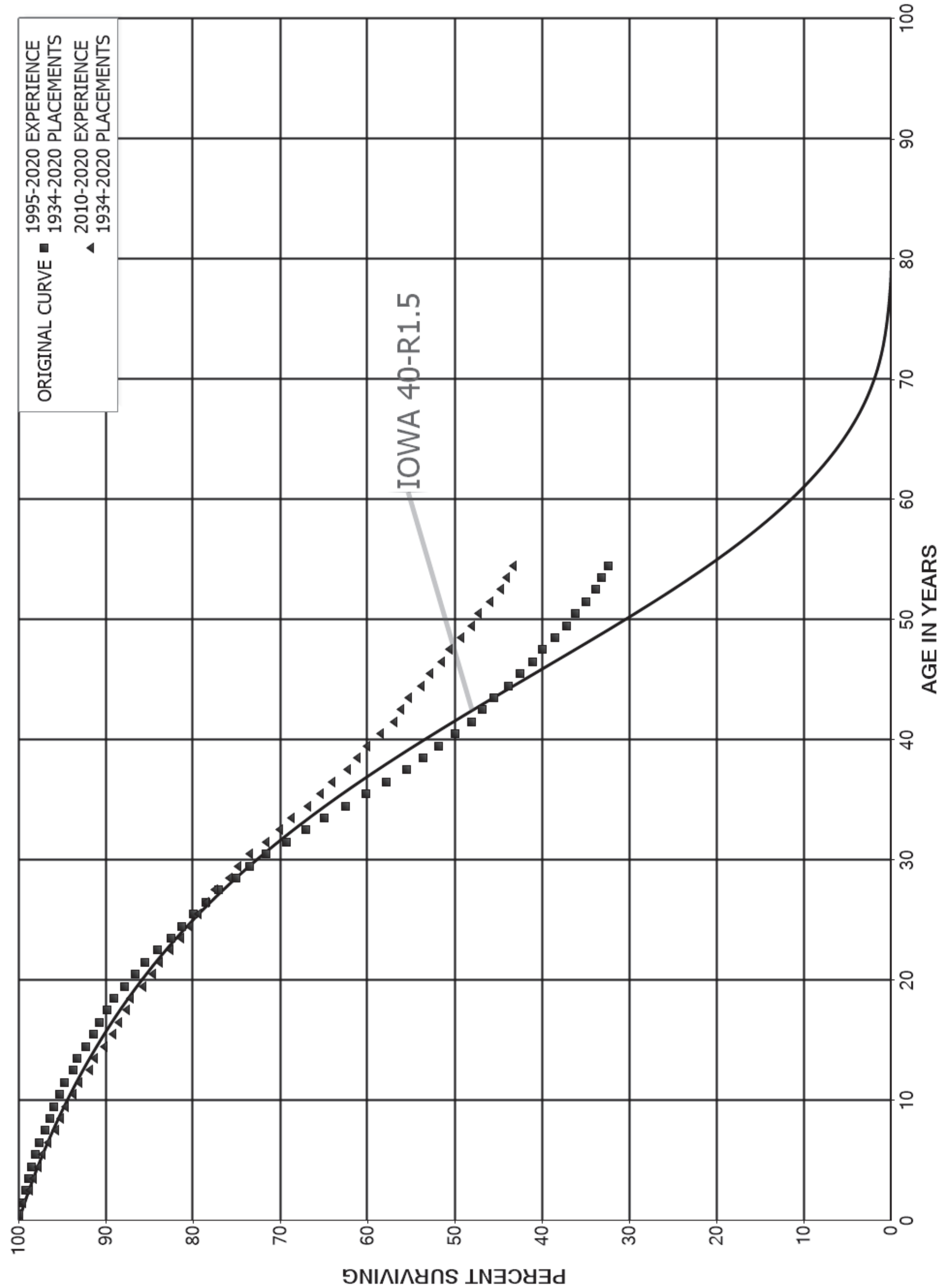
ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1950-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	347,521	2,096	0.0060	0.9940	81.99
40.5	323,348	2,825	0.0087	0.9913	81.50
41.5	269,765	3,399	0.0126	0.9874	80.79
42.5	233,684	2,667	0.0114	0.9886	79.77
43.5	199,288	1,340	0.0067	0.9933	78.86
44.5	182,549	15,608	0.0855	0.9145	78.33
45.5	149,901	2,345	0.0156	0.9844	71.63
46.5	121,286	662	0.0055	0.9945	70.51
47.5	108,552	265	0.0024	0.9976	70.13
48.5	83,499	30	0.0004	0.9996	69.95
49.5	12,470		0.0000	1.0000	69.93
50.5	6,486		0.0000	1.0000	69.93
51.5	10,160		0.0000	1.0000	69.93
52.5	10,160		0.0000	1.0000	69.93
53.5	13,725		0.0000	1.0000	69.93
54.5	10,189		0.0000	1.0000	69.93
55.5	10,189		0.0000	1.0000	69.93
56.5	10,189	0	0.0000	1.0000	69.93
57.5	9,861		0.0000	1.0000	69.93
58.5	9,468		0.0000	1.0000	69.93
59.5	9,530		0.0000	1.0000	69.93
60.5	8,731		0.0000	1.0000	69.93
61.5	8,731		0.0000	1.0000	69.93
62.5	5,056	10	0.0019	0.9981	69.93
63.5	5,047		0.0000	1.0000	69.79
64.5	1,322		0.0000	1.0000	69.79
65.5	1,322		0.0000	1.0000	69.79
66.5	1,322		0.0000	1.0000	69.79
67.5	1,322		0.0000	1.0000	69.79
68.5	1,322		0.0000	1.0000	69.79
69.5	63		0.0000	1.0000	69.79
70.5					69.79

UNITIL ENERGY SYSTEMS, INC.
ACCOUNTS 368.00 AND 368.01 LINE TRANSFORMERS AND LINE TRANSFORMER INSTALLATIONS
ORIGINAL AND SMOOTH SURVIVOR CURVES



UNITIL ENERGY SYSTEMS, INC.

ACCOUNTS 368.00 AND 368.01 LINE TRANSFORMERS AND LINE TRANSFORMER INSTALLATIONS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	50,122,228	6,946	0.0001	0.9999	100.00
0.5	47,694,159	158,759	0.0033	0.9967	99.99
1.5	44,821,723	229,584	0.0051	0.9949	99.65
2.5	40,823,635	119,846	0.0029	0.9971	99.14
3.5	38,721,755	151,719	0.0039	0.9961	98.85
4.5	37,023,144	145,628	0.0039	0.9961	98.46
5.5	35,459,121	170,482	0.0048	0.9952	98.08
6.5	34,132,690	245,179	0.0072	0.9928	97.61
7.5	32,859,421	166,854	0.0051	0.9949	96.90
8.5	29,365,130	144,351	0.0049	0.9951	96.41
9.5	29,895,387	201,802	0.0068	0.9932	95.94
10.5	28,601,778	178,621	0.0062	0.9938	95.29
11.5	27,629,648	268,986	0.0097	0.9903	94.70
12.5	25,328,240	144,199	0.0057	0.9943	93.77
13.5	22,077,564	226,159	0.0102	0.9898	93.24
14.5	20,172,362	188,064	0.0093	0.9907	92.28
15.5	18,583,024	141,206	0.0076	0.9924	91.42
16.5	17,461,823	174,158	0.0100	0.9900	90.73
17.5	16,024,030	132,393	0.0083	0.9917	89.82
18.5	14,772,899	213,927	0.0145	0.9855	89.08
19.5	14,000,221	183,917	0.0131	0.9869	87.79
20.5	13,467,678	178,425	0.0132	0.9868	86.64
21.5	12,743,076	206,248	0.0162	0.9838	85.49
22.5	12,190,924	226,275	0.0186	0.9814	84.11
23.5	11,328,980	175,995	0.0155	0.9845	82.55
24.5	10,814,738	182,719	0.0169	0.9831	81.26
25.5	10,307,315	182,829	0.0177	0.9823	79.89
26.5	9,913,203	184,284	0.0186	0.9814	78.47
27.5	9,523,189	237,041	0.0249	0.9751	77.02
28.5	9,170,369	198,610	0.0217	0.9783	75.10
29.5	8,793,418	221,654	0.0252	0.9748	73.47
30.5	8,235,763	269,185	0.0327	0.9673	71.62
31.5	7,639,563	240,465	0.0315	0.9685	69.28
32.5	6,785,723	220,961	0.0326	0.9674	67.10
33.5	5,931,820	218,249	0.0368	0.9632	64.91
34.5	5,043,714	190,764	0.0378	0.9622	62.53
35.5	4,446,711	169,680	0.0382	0.9618	60.16
36.5	4,052,375	166,877	0.0412	0.9588	57.86
37.5	3,613,973	124,171	0.0344	0.9656	55.48
38.5	3,352,206	107,267	0.0320	0.9680	53.58

UNITIL ENERGY SYSTEMS, INC.

ACCOUNTS 368.00 AND 368.01 LINE TRANSFORMERS AND LINE TRANSFORMER INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,106,320	115,811	0.0373	0.9627	51.86
40.5	2,819,092	102,328	0.0363	0.9637	49.93
41.5	2,555,270	67,568	0.0264	0.9736	48.12
42.5	2,270,861	66,502	0.0293	0.9707	46.84
43.5	2,091,153	77,213	0.0369	0.9631	45.47
44.5	1,871,593	55,936	0.0299	0.9701	43.79
45.5	1,751,592	59,093	0.0337	0.9663	42.48
46.5	1,430,852	39,848	0.0278	0.9722	41.05
47.5	1,131,172	40,067	0.0354	0.9646	39.91
48.5	948,984	32,453	0.0342	0.9658	38.49
49.5	817,499	21,954	0.0269	0.9731	37.18
50.5	713,123	24,824	0.0348	0.9652	36.18
51.5	652,424	20,749	0.0318	0.9682	34.92
52.5	583,981	11,845	0.0203	0.9797	33.81
53.5	536,613	10,972	0.0204	0.9796	33.12
54.5	478,967	9,644	0.0201	0.9799	32.45
55.5	439,688	7,193	0.0164	0.9836	31.79
56.5	412,407	8,761	0.0212	0.9788	31.27
57.5	370,619	10,047	0.0271	0.9729	30.61
58.5	326,025	5,791	0.0178	0.9822	29.78
59.5	289,712	5,761	0.0199	0.9801	29.25
60.5	248,453	5,129	0.0206	0.9794	28.67
61.5	204,354	6,971	0.0341	0.9659	28.08
62.5	177,847	4,686	0.0263	0.9737	27.12
63.5	145,227	5,094	0.0351	0.9649	26.40
64.5	111,029	3,190	0.0287	0.9713	25.48
65.5	88,173	1,772	0.0201	0.9799	24.75
66.5	78,260	1,102	0.0141	0.9859	24.25
67.5	56,246	556	0.0099	0.9901	23.91
68.5	47,250	99	0.0021	0.9979	23.67
69.5	36,585	521	0.0142	0.9858	23.62
70.5	32,976	904	0.0274	0.9726	23.28
71.5	28,070	117	0.0042	0.9958	22.65
72.5	22,347	153	0.0068	0.9932	22.55
73.5	16,479	113	0.0069	0.9931	22.40
74.5	15,235	70	0.0046	0.9954	22.24
75.5	14,140	167	0.0118	0.9882	22.14
76.5	13,882		0.0000	1.0000	21.88
77.5	13,429	63	0.0047	0.9953	21.88
78.5	11,696	204	0.0174	0.9826	21.78

UNITIL ENERGY SYSTEMS, INC.

ACCOUNTS 368.00 AND 368.01 LINE TRANSFORMERS AND LINE TRANSFORMER INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	8,972	460	0.0512	0.9488	21.40
80.5	6,202		0.0000	1.0000	20.30
81.5	6,008		0.0000	1.0000	20.30
82.5	6,008		0.0000	1.0000	20.30
83.5	5,628		0.0000	1.0000	20.30
84.5	3,681		0.0000	1.0000	20.30
85.5	3,034		0.0000	1.0000	20.30
86.5					20.30

UNITIL ENERGY SYSTEMS, INC.

ACCOUNTS 368.00 AND 368.01 LINE TRANSFORMERS AND LINE TRANSFORMER INSTALLATIONS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	27,387,756	1,357	0.0000	1.0000	100.00
0.5	26,046,926	145,722	0.0056	0.9944	100.00
1.5	25,304,238	213,284	0.0084	0.9916	99.44
2.5	24,607,770	102,715	0.0042	0.9958	98.60
3.5	24,345,365	132,165	0.0054	0.9946	98.19
4.5	24,196,406	124,178	0.0051	0.9949	97.65
5.5	23,592,012	145,251	0.0062	0.9938	97.15
6.5	22,944,506	217,801	0.0095	0.9905	96.55
7.5	22,327,099	139,822	0.0063	0.9937	95.64
8.5	18,551,106	113,317	0.0061	0.9939	95.04
9.5	19,379,637	163,990	0.0085	0.9915	94.46
10.5	18,867,245	146,505	0.0078	0.9922	93.66
11.5	18,146,478	228,567	0.0126	0.9874	92.93
12.5	16,467,036	98,022	0.0060	0.9940	91.76
13.5	13,598,262	172,789	0.0127	0.9873	91.21
14.5	11,967,072	130,253	0.0109	0.9891	90.06
15.5	10,512,437	74,602	0.0071	0.9929	89.08
16.5	9,434,819	99,836	0.0106	0.9894	88.44
17.5	8,163,019	44,661	0.0055	0.9945	87.51
18.5	7,016,467	118,324	0.0169	0.9831	87.03
19.5	6,594,092	77,582	0.0118	0.9882	85.56
20.5	6,099,060	59,768	0.0098	0.9902	84.55
21.5	5,803,419	84,085	0.0145	0.9855	83.73
22.5	5,865,129	85,759	0.0146	0.9854	82.51
23.5	5,855,195	70,991	0.0121	0.9879	81.31
24.5	5,854,494	78,969	0.0135	0.9865	80.32
25.5	5,665,412	56,430	0.0100	0.9900	79.24
26.5	5,666,060	74,852	0.0132	0.9868	78.45
27.5	5,509,993	118,187	0.0214	0.9786	77.41
28.5	5,367,445	71,053	0.0132	0.9868	75.75
29.5	5,287,142	92,955	0.0176	0.9824	74.75
30.5	5,068,610	130,087	0.0257	0.9743	73.43
31.5	4,833,790	107,278	0.0222	0.9778	71.55
32.5	4,191,475	82,770	0.0197	0.9803	69.96
33.5	3,582,372	95,768	0.0267	0.9733	68.58
34.5	2,821,596	61,302	0.0217	0.9783	66.75
35.5	2,613,196	52,567	0.0201	0.9799	65.30
36.5	2,592,095	71,132	0.0274	0.9726	63.98
37.5	2,357,617	43,561	0.0185	0.9815	62.23
38.5	2,237,356	39,511	0.0177	0.9823	61.08

UNITIL ENERGY SYSTEMS, INC.

ACCOUNTS 368.00 AND 368.01 LINE TRANSFORMERS AND LINE TRANSFORMER INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,105,870	56,140	0.0267	0.9733	60.00
40.5	1,895,687	52,145	0.0275	0.9725	58.40
41.5	1,711,406	20,522	0.0120	0.9880	56.79
42.5	1,506,910	23,840	0.0158	0.9842	56.11
43.5	1,403,238	38,691	0.0276	0.9724	55.22
44.5	1,258,230	23,387	0.0186	0.9814	53.70
45.5	1,188,907	29,655	0.0249	0.9751	52.70
46.5	926,161	15,292	0.0165	0.9835	51.39
47.5	691,815	18,185	0.0263	0.9737	50.54
48.5	571,361	14,180	0.0248	0.9752	49.21
49.5	509,882	8,637	0.0169	0.9831	47.99
50.5	463,026	13,544	0.0293	0.9707	47.18
51.5	440,991	11,195	0.0254	0.9746	45.80
52.5	413,719	6,809	0.0165	0.9835	44.63
53.5	405,523	6,973	0.0172	0.9828	43.90
54.5	379,611	8,001	0.0211	0.9789	43.15
55.5	355,267	6,925	0.0195	0.9805	42.24
56.5	353,804	8,761	0.0248	0.9752	41.41
57.5	322,164	10,047	0.0312	0.9688	40.39
58.5	288,339	5,791	0.0201	0.9799	39.13
59.5	255,527	5,761	0.0225	0.9775	38.34
60.5	216,821	5,129	0.0237	0.9763	37.48
61.5	178,489	6,971	0.0391	0.9609	36.59
62.5	159,297	4,686	0.0294	0.9706	35.16
63.5	129,394	5,094	0.0394	0.9606	34.13
64.5	96,432	3,190	0.0331	0.9669	32.78
65.5	73,667	1,772	0.0241	0.9759	31.70
66.5	64,263	1,102	0.0171	0.9829	30.94
67.5	43,919	556	0.0127	0.9873	30.41
68.5	37,533	99	0.0027	0.9973	30.02
69.5	29,357	521	0.0178	0.9822	29.94
70.5	26,012	904	0.0347	0.9653	29.41
71.5	21,106	117	0.0055	0.9945	28.39
72.5	15,961	153	0.0096	0.9904	28.23
73.5	12,041	113	0.0094	0.9906	27.96
74.5	11,443	70	0.0061	0.9939	27.70
75.5	14,140	167	0.0118	0.9882	27.53
76.5	13,882		0.0000	1.0000	27.20
77.5	13,429	63	0.0047	0.9953	27.20
78.5	11,696	204	0.0174	0.9826	27.08

UNITIL ENERGY SYSTEMS, INC.

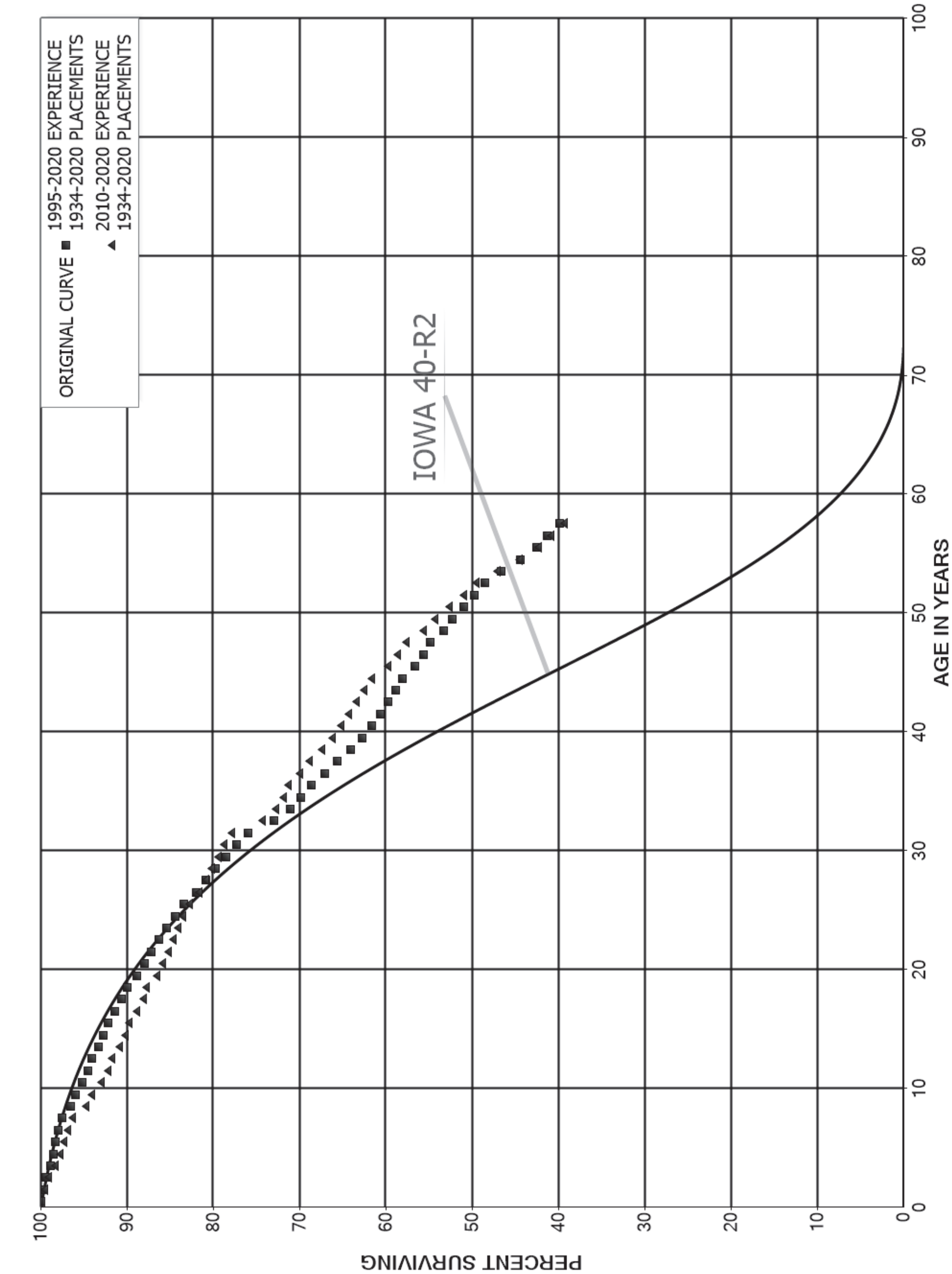
ACCOUNTS 368.00 AND 368.01 LINE TRANSFORMERS AND LINE TRANSFORMER INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	8,972	460	0.0512	0.9488	26.60
80.5	6,202		0.0000	1.0000	25.24
81.5	6,008		0.0000	1.0000	25.24
82.5	6,008		0.0000	1.0000	25.24
83.5	5,628		0.0000	1.0000	25.24
84.5	3,681		0.0000	1.0000	25.24
85.5	3,034		0.0000	1.0000	25.24
86.5					25.24

UNITIL ENERGY SYSTEMS, INC.
ACCOUNT 369.00 SERVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	22,522,568	11,916	0.0005	0.9995	100.00
0.5	21,589,412	69,299	0.0032	0.9968	99.95
1.5	20,381,625	58,388	0.0029	0.9971	99.63
2.5	19,390,872	88,257	0.0046	0.9954	99.34
3.5	18,369,269	71,809	0.0039	0.9961	98.89
4.5	17,461,677	47,566	0.0027	0.9973	98.50
5.5	16,894,486	58,852	0.0035	0.9965	98.23
6.5	16,207,018	72,793	0.0045	0.9955	97.89
7.5	15,340,023	153,619	0.0100	0.9900	97.45
8.5	14,920,185	78,450	0.0053	0.9947	96.48
9.5	14,604,880	119,950	0.0082	0.9918	95.97
10.5	13,626,204	95,379	0.0070	0.9930	95.18
11.5	12,889,529	59,650	0.0046	0.9954	94.51
12.5	11,915,627	95,854	0.0080	0.9920	94.08
13.5	11,246,410	70,477	0.0063	0.9937	93.32
14.5	10,733,985	66,985	0.0062	0.9938	92.74
15.5	10,040,887	84,508	0.0084	0.9916	92.16
16.5	9,458,353	83,046	0.0088	0.9912	91.38
17.5	8,912,554	61,843	0.0069	0.9931	90.58
18.5	8,367,100	106,586	0.0127	0.9873	89.95
19.5	7,852,198	70,607	0.0090	0.9910	88.80
20.5	7,386,451	73,738	0.0100	0.9900	88.01
21.5	6,847,338	68,603	0.0100	0.9900	87.13
22.5	6,438,942	63,566	0.0099	0.9901	86.25
23.5	5,841,306	66,081	0.0113	0.9887	85.40
24.5	5,426,993	66,937	0.0123	0.9877	84.44
25.5	5,061,471	86,221	0.0170	0.9830	83.40
26.5	4,690,015	65,841	0.0140	0.9860	81.97
27.5	4,399,286	62,528	0.0142	0.9858	80.82
28.5	4,092,892	62,487	0.0153	0.9847	79.68
29.5	3,727,136	54,834	0.0147	0.9853	78.46
30.5	3,453,611	60,340	0.0175	0.9825	77.30
31.5	3,172,332	127,906	0.0403	0.9597	75.95
32.5	2,796,288	69,780	0.0250	0.9750	72.89
33.5	2,467,209	44,792	0.0182	0.9818	71.07
34.5	2,129,005	35,097	0.0165	0.9835	69.78
35.5	1,870,208	43,061	0.0230	0.9770	68.63
36.5	1,664,797	35,119	0.0211	0.9789	67.05
37.5	1,498,330	36,464	0.0243	0.9757	65.64
38.5	1,367,767	28,038	0.0205	0.9795	64.04

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,254,147	22,948	0.0183	0.9817	62.73
40.5	1,158,211	17,677	0.0153	0.9847	61.58
41.5	1,027,014	15,473	0.0151	0.9849	60.64
42.5	900,046	13,083	0.0145	0.9855	59.73
43.5	751,239	10,178	0.0135	0.9865	58.86
44.5	652,230	16,795	0.0257	0.9743	58.06
45.5	549,394	9,357	0.0170	0.9830	56.57
46.5	481,730	6,964	0.0145	0.9855	55.60
47.5	412,153	11,452	0.0278	0.9722	54.80
48.5	324,970	6,021	0.0185	0.9815	53.28
49.5	299,135	7,386	0.0247	0.9753	52.29
50.5	257,344	6,564	0.0255	0.9745	51.00
51.5	226,196	5,214	0.0231	0.9769	49.70
52.5	187,694	7,596	0.0405	0.9595	48.55
53.5	162,046	7,601	0.0469	0.9531	46.59
54.5	140,577	6,116	0.0435	0.9565	44.40
55.5	123,984	3,597	0.0290	0.9710	42.47
56.5	106,601	3,596	0.0337	0.9663	41.24
57.5	88,693	3,570	0.0402	0.9598	39.85
58.5	72,081	2,254	0.0313	0.9687	38.24
59.5	56,972	3,661	0.0643	0.9357	37.05
60.5	45,819	2,158	0.0471	0.9529	34.67
61.5	34,859	771	0.0221	0.9779	33.03
62.5	29,693	876	0.0295	0.9705	32.30
63.5	21,956	1,109	0.0505	0.9495	31.35
64.5	14,740	296	0.0201	0.9799	29.77
65.5	12,925	1,077	0.0833	0.9167	29.17
66.5	10,511	130	0.0123	0.9877	26.74
67.5	9,558	68	0.0071	0.9929	26.41
68.5	9,247		0.0000	1.0000	26.22
69.5	8,464	101	0.0120	0.9880	26.22
70.5	7,816	13	0.0017	0.9983	25.91
71.5	7,504		0.0000	1.0000	25.86
72.5	7,141		0.0000	1.0000	25.86
73.5	6,982	28	0.0040	0.9960	25.86
74.5	6,887		0.0000	1.0000	25.76
75.5	6,775	158	0.0233	0.9767	25.76
76.5	6,508	19	0.0030	0.9970	25.16
77.5	4,269	11	0.0027	0.9973	25.09
78.5	4,253	37	0.0088	0.9912	25.02

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	4,148	34	0.0082	0.9918	24.80
80.5	4,007		0.0000	1.0000	24.60
81.5	3,521	11	0.0032	0.9968	24.60
82.5	3,350	11	0.0034	0.9966	24.52
83.5	3,333	11	0.0034	0.9966	24.43
84.5	3,272	11	0.0035	0.9965	24.35
85.5	2,956		0.0000	1.0000	24.26
86.5					24.26

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	12,134,602	9,525	0.0008	0.9992	100.00
0.5	11,733,066	63,879	0.0054	0.9946	99.92
1.5	11,401,312	52,061	0.0046	0.9954	99.38
2.5	10,867,886	80,771	0.0074	0.9926	98.92
3.5	10,120,981	62,873	0.0062	0.9938	98.19
4.5	9,790,766	37,539	0.0038	0.9962	97.58
5.5	9,716,931	47,437	0.0049	0.9951	97.20
6.5	9,413,645	59,159	0.0063	0.9937	96.73
7.5	8,877,550	138,102	0.0156	0.9844	96.12
8.5	8,692,420	60,677	0.0070	0.9930	94.63
9.5	8,625,923	99,933	0.0116	0.9884	93.97
10.5	8,047,914	73,320	0.0091	0.9909	92.88
11.5	7,638,058	36,120	0.0047	0.9953	92.03
12.5	7,153,163	71,102	0.0099	0.9901	91.60
13.5	6,799,708	43,625	0.0064	0.9936	90.69
14.5	6,538,447	38,516	0.0059	0.9941	90.10
15.5	6,075,421	53,913	0.0089	0.9911	89.57
16.5	5,620,871	49,480	0.0088	0.9912	88.78
17.5	5,213,165	25,459	0.0049	0.9951	88.00
18.5	4,924,489	68,732	0.0140	0.9860	87.57
19.5	4,584,839	30,770	0.0067	0.9933	86.34
20.5	4,323,320	32,743	0.0076	0.9924	85.77
21.5	4,034,779	29,561	0.0073	0.9927	85.12
22.5	3,877,172	23,361	0.0060	0.9940	84.49
23.5	3,608,720	26,715	0.0074	0.9926	83.98
24.5	3,444,604	28,624	0.0083	0.9917	83.36
25.5	3,241,524	47,689	0.0147	0.9853	82.67
26.5	2,999,362	27,170	0.0091	0.9909	81.45
27.5	2,838,103	24,319	0.0086	0.9914	80.71
28.5	2,661,164	25,396	0.0095	0.9905	80.02
29.5	2,442,029	19,671	0.0081	0.9919	79.26
30.5	2,312,892	27,326	0.0118	0.9882	78.62
31.5	2,177,866	98,014	0.0450	0.9550	77.69
32.5	1,956,936	42,512	0.0217	0.9783	74.20
33.5	1,728,199	19,527	0.0113	0.9887	72.58
34.5	1,488,117	12,684	0.0085	0.9915	71.76
35.5	1,314,659	24,297	0.0185	0.9815	71.15
36.5	1,193,562	19,090	0.0160	0.9840	69.84
37.5	1,115,179	23,852	0.0214	0.9786	68.72
38.5	1,013,060	17,775	0.0175	0.9825	67.25

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	947,581	14,597	0.0154	0.9846	66.07
40.5	889,916	11,613	0.0130	0.9870	65.05
41.5	803,755	11,192	0.0139	0.9861	64.20
42.5	703,590	10,180	0.0145	0.9855	63.31
43.5	577,191	8,135	0.0141	0.9859	62.39
44.5	496,849	14,985	0.0302	0.9698	61.51
45.5	413,826	8,171	0.0197	0.9803	59.66
46.5	366,093	6,133	0.0168	0.9832	58.48
47.5	314,430	10,995	0.0350	0.9650	57.50
48.5	246,383	5,791	0.0235	0.9765	55.49
49.5	235,982	7,386	0.0313	0.9687	54.19
50.5	206,340	6,564	0.0318	0.9682	52.49
51.5	180,513	5,214	0.0289	0.9711	50.82
52.5	153,753	7,596	0.0494	0.9506	49.35
53.5	139,825	7,601	0.0544	0.9456	46.91
54.5	122,515	6,116	0.0499	0.9501	44.36
55.5	108,637	3,597	0.0331	0.9669	42.15
56.5	93,085	3,596	0.0386	0.9614	40.75
57.5	77,349	3,570	0.0461	0.9539	39.18
58.5	62,731	2,254	0.0359	0.9641	37.37
59.5	51,381	3,661	0.0713	0.9287	36.03
60.5	37,947	2,158	0.0569	0.9431	33.46
61.5	27,435	771	0.0281	0.9719	31.56
62.5	22,450	876	0.0390	0.9610	30.67
63.5	14,851	1,109	0.0747	0.9253	29.47
64.5	7,776	296	0.0380	0.9620	27.27
65.5	6,088	1,077	0.1768	0.8232	26.24
66.5	6,081	130	0.0213	0.9787	21.60
67.5	5,162	68	0.0132	0.9868	21.14
68.5	4,922		0.0000	1.0000	20.86
69.5	4,246	101	0.0238	0.9762	20.86
70.5	4,084	13	0.0032	0.9968	20.36
71.5	3,932		0.0000	1.0000	20.30
72.5	3,584		0.0000	1.0000	20.30
73.5	3,474	28	0.0080	0.9920	20.30
74.5	3,684		0.0000	1.0000	20.13
75.5	6,775	158	0.0233	0.9767	20.13
76.5	6,508	19	0.0030	0.9970	19.66
77.5	4,269	11	0.0027	0.9973	19.60
78.5	4,253	37	0.0088	0.9912	19.55

UNITIL ENERGY SYSTEMS, INC.

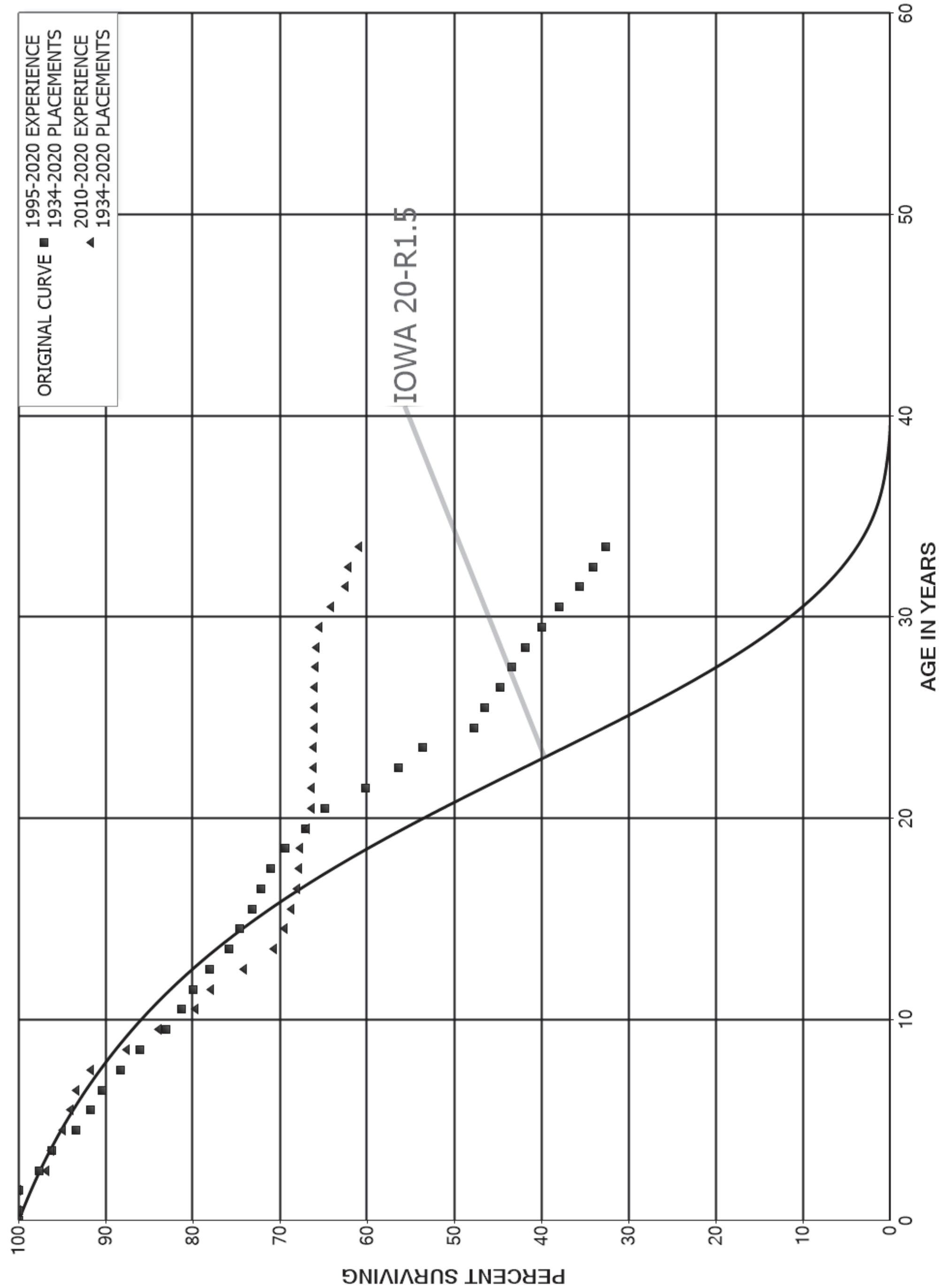
ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	4,148	34	0.0082	0.9918	19.38
80.5	4,007		0.0000	1.0000	19.22
81.5	3,521	11	0.0032	0.9968	19.22
82.5	3,350	11	0.0034	0.9966	19.16
83.5	3,333	11	0.0034	0.9966	19.09
84.5	3,272	11	0.0035	0.9965	19.03
85.5	2,956		0.0000	1.0000	18.96
86.5					18.96

UNITIL ENERGY SYSTEMS, INC.
ACCOUNTS 370.00 AND 370.01 METERS AND METER INSTALLATIONS
ORIGINAL AND SMOOTH SURVIVOR CURVES



UNITIL ENERGY SYSTEMS, INC.

ACCOUNTS 370.00 AND 370.01 METERS AND METER INSTALLATIONS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	18,286,749	101	0.0000	1.0000	100.00
0.5	17,563,289	18,092	0.0010	0.9990	100.00
1.5	17,008,090	379,503	0.0223	0.9777	99.90
2.5	15,914,682	235,278	0.0148	0.9852	97.67
3.5	15,200,084	441,599	0.0291	0.9709	96.22
4.5	14,510,727	259,229	0.0179	0.9821	93.43
5.5	14,317,150	212,937	0.0149	0.9851	91.76
6.5	14,517,888	337,144	0.0232	0.9768	90.39
7.5	14,740,748	367,308	0.0249	0.9751	88.30
8.5	14,766,762	521,957	0.0353	0.9647	86.09
9.5	14,747,626	317,518	0.0215	0.9785	83.05
10.5	15,111,805	233,743	0.0155	0.9845	81.26
11.5	14,885,159	355,012	0.0239	0.9761	80.01
12.5	14,509,833	415,039	0.0286	0.9714	78.10
13.5	12,106,944	205,607	0.0170	0.9830	75.86
14.5	11,846,611	215,637	0.0182	0.9818	74.58
15.5	11,576,600	167,143	0.0144	0.9856	73.22
16.5	11,374,974	170,702	0.0150	0.9850	72.16
17.5	11,172,088	259,389	0.0232	0.9768	71.08
18.5	10,896,419	370,448	0.0340	0.9660	69.43
19.5	10,503,036	353,457	0.0337	0.9663	67.07
20.5	9,958,910	716,002	0.0719	0.9281	64.81
21.5	9,113,641	561,716	0.0616	0.9384	60.15
22.5	8,332,069	419,088	0.0503	0.9497	56.44
23.5	7,755,366	846,458	0.1091	0.8909	53.60
24.5	6,607,141	177,062	0.0268	0.9732	47.75
25.5	6,064,916	232,218	0.0383	0.9617	46.47
26.5	5,155,937	149,968	0.0291	0.9709	44.70
27.5	4,312,552	152,432	0.0353	0.9647	43.40
28.5	3,509,715	159,497	0.0454	0.9546	41.86
29.5	3,090,399	155,291	0.0502	0.9498	39.96
30.5	2,512,560	155,012	0.0617	0.9383	37.95
31.5	1,999,979	84,153	0.0421	0.9579	35.61
32.5	1,330,371	57,549	0.0433	0.9567	34.11
33.5	916,309	59,088	0.0645	0.9355	32.64
34.5	407,472	55,702	0.1367	0.8633	30.53
35.5	283,601	7,995	0.0282	0.9718	26.36
36.5	221,702	11,356	0.0512	0.9488	25.61
37.5	197,437	879	0.0045	0.9955	24.30
38.5	189,701	2,575	0.0136	0.9864	24.19

UNITIL ENERGY SYSTEMS, INC.

ACCOUNTS 370.00 AND 370.01 METERS AND METER INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	177,591	702	0.0040	0.9960	23.87
40.5	166,668	1,717	0.0103	0.9897	23.77
41.5	135,393	4,319	0.0319	0.9681	23.53
42.5	124,006	205	0.0017	0.9983	22.78
43.5	119,064	922	0.0077	0.9923	22.74
44.5	109,221		0.0000	1.0000	22.56
45.5	104,640		0.0000	1.0000	22.56
46.5	99,226		0.0000	1.0000	22.56
47.5	86,635		0.0000	1.0000	22.56
48.5	82,888		0.0000	1.0000	22.56
49.5	76,623		0.0000	1.0000	22.56
50.5	70,356	24	0.0003	0.9997	22.56
51.5	67,693		0.0000	1.0000	22.55
52.5	62,375	1,308	0.0210	0.9790	22.55
53.5	59,175	211	0.0036	0.9964	22.08
54.5	52,589	979	0.0186	0.9814	22.00
55.5	48,802	922	0.0189	0.9811	21.59
56.5	40,394	884	0.0219	0.9781	21.19
57.5	37,003	2,239	0.0605	0.9395	20.72
58.5	29,110	238	0.0082	0.9918	19.47
59.5	26,483	361	0.0136	0.9864	19.31
60.5	20,767		0.0000	1.0000	19.05
61.5	16,093	108	0.0067	0.9933	19.05
62.5	13,598	956	0.0703	0.9297	18.92
63.5	10,277	265	0.0258	0.9742	17.59
64.5	9,249	3	0.0003	0.9997	17.13
65.5	8,723	1,335	0.1531	0.8469	17.13
66.5	5,796	119	0.0205	0.9795	14.51
67.5	5,346	96	0.0180	0.9820	14.21
68.5	5,190	64	0.0123	0.9877	13.95
69.5	4,548		0.0000	1.0000	13.78
70.5	4,522		0.0000	1.0000	13.78
71.5	3,909		0.0000	1.0000	13.78
72.5	3,746	23	0.0061	0.9939	13.78
73.5	3,506	50	0.0141	0.9859	13.70
74.5	3,336	764	0.2290	0.7710	13.50
75.5	2,573	1,025	0.3985	0.6015	10.41
76.5	1,547	488	0.3151	0.6849	6.26
77.5	1,060	267	0.2520	0.7480	4.29
78.5	793	15	0.0189	0.9811	3.21
79.5	778	778	1.0000		3.15
80.5					

UNITIL ENERGY SYSTEMS, INC.

ACCOUNTS 370.00 AND 370.01 METERS AND METER INSTALLATIONS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	9,191,249		0.0000	1.0000	100.00
0.5	7,813,493	934	0.0001	0.9999	100.00
1.5	6,746,221	218,679	0.0324	0.9676	99.99
2.5	8,079,885	52,148	0.0065	0.9935	96.75
3.5	7,705,425	105,339	0.0137	0.9863	96.12
4.5	7,038,638	59,726	0.0085	0.9915	94.81
5.5	6,692,258	53,814	0.0080	0.9920	94.00
6.5	6,369,476	112,274	0.0176	0.9824	93.25
7.5	5,904,842	261,999	0.0444	0.9556	91.60
8.5	5,088,764	214,001	0.0421	0.9579	87.54
9.5	5,143,323	262,004	0.0509	0.9491	83.86
10.5	4,793,703	102,812	0.0214	0.9786	79.59
11.5	4,731,019	232,648	0.0492	0.9508	77.88
12.5	4,407,124	202,821	0.0460	0.9540	74.05
13.5	2,357,152	43,305	0.0184	0.9816	70.64
14.5	2,448,646	25,805	0.0105	0.9895	69.34
15.5	2,898,886	26,156	0.0090	0.9910	68.61
16.5	3,421,473	12,420	0.0036	0.9964	67.99
17.5	3,889,511	4,627	0.0012	0.9988	67.75
18.5	4,026,110	50,376	0.0125	0.9875	67.67
19.5	4,322,657	34,601	0.0080	0.9920	66.82
20.5	4,395,620	2,952	0.0007	0.9993	66.29
21.5	4,773,750	9,588	0.0020	0.9980	66.24
22.5	4,898,638	3,815	0.0008	0.9992	66.11
23.5	5,228,825	3,799	0.0007	0.9993	66.06
24.5	5,006,434	2,051	0.0004	0.9996	66.01
25.5	4,760,497	4,597	0.0010	0.9990	65.98
26.5	4,106,647	2,724	0.0007	0.9993	65.92
27.5	3,439,783	8,598	0.0025	0.9975	65.87
28.5	2,807,475	11,471	0.0041	0.9959	65.71
29.5	2,563,909	52,746	0.0206	0.9794	65.44
30.5	2,114,249	54,544	0.0258	0.9742	64.09
31.5	1,711,138	11,438	0.0067	0.9933	62.44
32.5	1,126,179	22,450	0.0199	0.9801	62.02
33.5	753,694	27,837	0.0369	0.9631	60.79
34.5	277,644	17,948	0.0646	0.9354	58.54
35.5	193,591	7,995	0.0413	0.9587	54.76
36.5	143,059	11,356	0.0794	0.9206	52.50
37.5	124,062	879	0.0071	0.9929	48.33
38.5	119,926	2,575	0.0215	0.9785	47.99

UNITIL ENERGY SYSTEMS, INC.

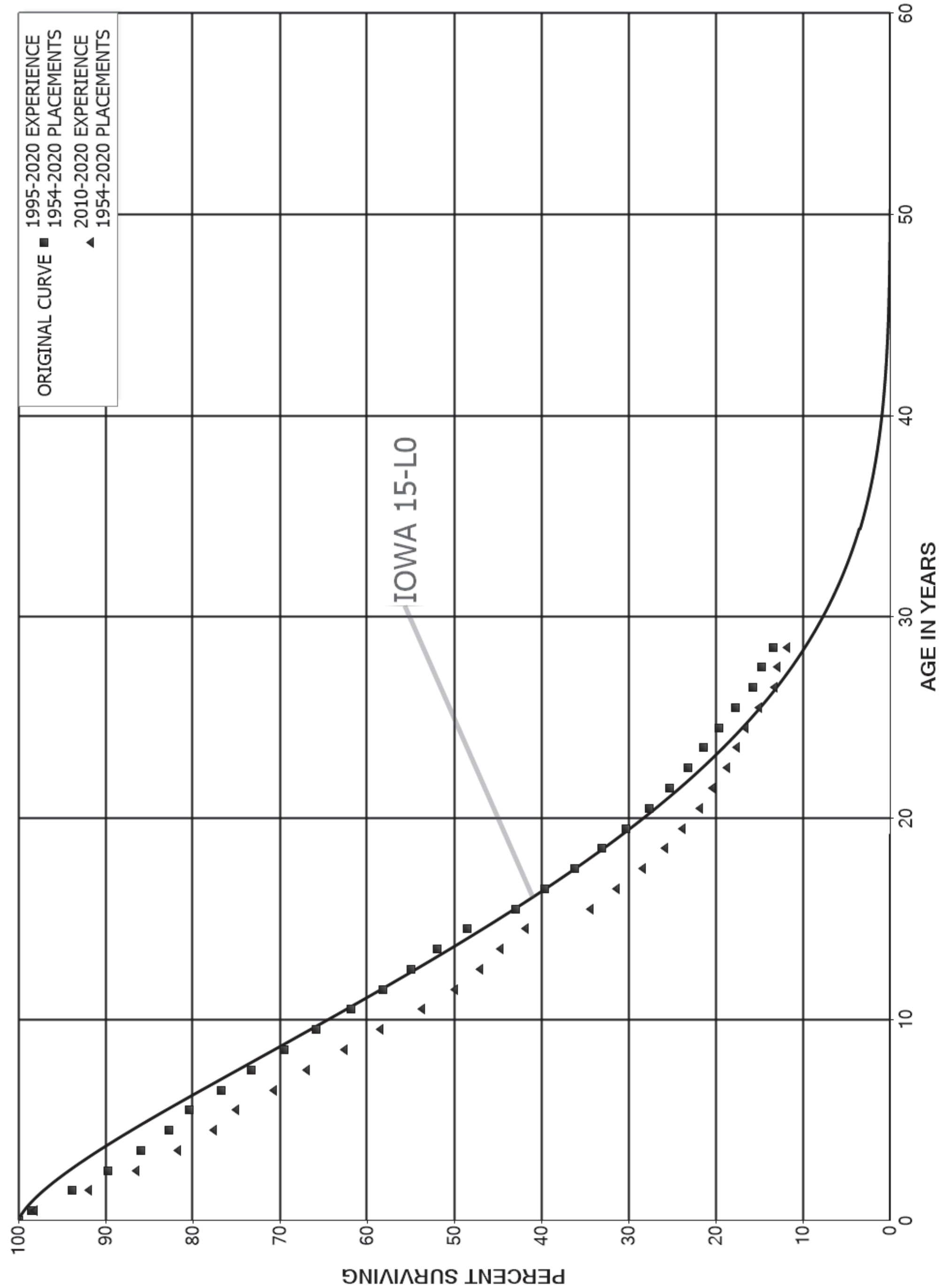
ACCOUNTS 370.00 AND 370.01 METERS AND METER INSTALLATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1934-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	114,243	702	0.0061	0.9939	46.96
40.5	104,006	1,717	0.0165	0.9835	46.67
41.5	77,717	4,319	0.0556	0.9444	45.90
42.5	68,078	205	0.0030	0.9970	43.35
43.5	68,026	922	0.0135	0.9865	43.22
44.5	61,464		0.0000	1.0000	42.63
45.5	64,782		0.0000	1.0000	42.63
46.5	60,860		0.0000	1.0000	42.63
47.5	53,879		0.0000	1.0000	42.63
48.5	53,626		0.0000	1.0000	42.63
49.5	53,641		0.0000	1.0000	42.63
50.5	53,026	24	0.0005	0.9995	42.63
51.5	53,673		0.0000	1.0000	42.61
52.5	51,604	1,308	0.0253	0.9747	42.61
53.5	51,383	211	0.0041	0.9959	41.53
54.5	45,509	979	0.0215	0.9785	41.36
55.5	42,911	922	0.0215	0.9785	40.47
56.5	33,810	884	0.0262	0.9738	39.60
57.5	30,099	2,239	0.0744	0.9256	38.57
58.5	23,472	238	0.0101	0.9899	35.70
59.5	21,122	361	0.0171	0.9829	35.34
60.5	15,240		0.0000	1.0000	34.73
61.5	12,068	108	0.0089	0.9911	34.73
62.5	9,909	956	0.0965	0.9035	34.42
63.5	6,804	265	0.0389	0.9611	31.10
64.5	5,841	3	0.0005	0.9995	29.89
65.5	5,315	1,335	0.2512	0.7488	29.87
66.5	2,387	119	0.0498	0.9502	22.37
67.5	1,937	96	0.0496	0.9504	21.25
68.5	1,804	64	0.0355	0.9645	20.20
69.5	1,212		0.0000	1.0000	19.48
70.5	1,949		0.0000	1.0000	19.48
71.5	2,362		0.0000	1.0000	19.48
72.5	2,686	23	0.0084	0.9916	19.48
73.5	2,713	50	0.0183	0.9817	19.32
74.5	2,559	764	0.2986	0.7014	18.97
75.5	2,573	1,025	0.3985	0.6015	13.30
76.5	1,547	488	0.3151	0.6849	8.00
77.5	1,060	267	0.2520	0.7480	5.48
78.5	793	15	0.0189	0.9811	4.10
79.5	778	778	1.0000		4.02
80.5					

UNITIL ENERGY SYSTEMS, INC.
ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES
ORIGINAL AND SMOOTH SURVIVOR CURVES



UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1954-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,474,518	51,423	0.0148	0.9852	100.00
0.5	3,318,052	156,539	0.0472	0.9528	98.52
1.5	2,985,830	130,315	0.0436	0.9564	93.87
2.5	2,661,480	111,889	0.0420	0.9580	89.78
3.5	2,440,051	92,317	0.0378	0.9622	86.00
4.5	2,139,988	61,779	0.0289	0.9711	82.75
5.5	1,949,282	88,777	0.0455	0.9545	80.36
6.5	1,783,851	80,420	0.0451	0.9549	76.70
7.5	1,602,467	82,117	0.0512	0.9488	73.24
8.5	1,345,551	70,084	0.0521	0.9479	69.49
9.5	1,219,333	74,687	0.0613	0.9387	65.87
10.5	1,125,739	66,748	0.0593	0.9407	61.83
11.5	1,075,712	58,921	0.0548	0.9452	58.17
12.5	1,023,470	57,448	0.0561	0.9439	54.98
13.5	976,353	63,367	0.0649	0.9351	51.90
14.5	919,667	105,132	0.1143	0.8857	48.53
15.5	828,685	65,624	0.0792	0.9208	42.98
16.5	757,631	64,433	0.0850	0.9150	39.58
17.5	700,071	61,396	0.0877	0.9123	36.21
18.5	641,659	53,887	0.0840	0.9160	33.03
19.5	578,656	51,636	0.0892	0.9108	30.26
20.5	514,410	41,957	0.0816	0.9184	27.56
21.5	461,887	39,753	0.0861	0.9139	25.31
22.5	417,080	32,076	0.0769	0.9231	23.13
23.5	368,131	29,319	0.0796	0.9204	21.35
24.5	337,136	33,430	0.0992	0.9008	19.65
25.5	287,419	31,953	0.1112	0.8888	17.71
26.5	240,927	15,797	0.0656	0.9344	15.74
27.5	215,896	19,616	0.0909	0.9091	14.70
28.5	181,756	19,426	0.1069	0.8931	13.37
29.5	159,302	13,983	0.0878	0.9122	11.94
30.5	142,569	9,853	0.0691	0.9309	10.89
31.5	132,178	9,123	0.0690	0.9310	10.14
32.5	125,441	6,170	0.0492	0.9508	9.44
33.5	114,222	6,080	0.0532	0.9468	8.98
34.5	104,131	4,333	0.0416	0.9584	8.50
35.5	99,911	5,109	0.0511	0.9489	8.14
36.5	89,499	2,240	0.0250	0.9750	7.73
37.5	80,332	4,922	0.0613	0.9387	7.53
38.5	70,166	1,712	0.0244	0.9756	7.07

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1954-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	64,767	2,537	0.0392	0.9608	6.90
40.5	56,710	1,911	0.0337	0.9663	6.63
41.5	49,099	692	0.0141	0.9859	6.41
42.5	47,053	306	0.0065	0.9935	6.32
43.5	42,791	1,310	0.0306	0.9694	6.27
44.5	38,004	2,774	0.0730	0.9270	6.08
45.5	34,005	1,180	0.0347	0.9653	5.64
46.5	30,809	480	0.0156	0.9844	5.44
47.5	28,717	1,435	0.0500	0.9500	5.36
48.5	25,773	986	0.0383	0.9617	5.09
49.5	24,333	1,580	0.0649	0.9351	4.90
50.5	21,151	683	0.0323	0.9677	4.58
51.5	18,288	389	0.0213	0.9787	4.43
52.5	14,289	242	0.0169	0.9831	4.34
53.5	12,090		0.0000	1.0000	4.26
54.5	10,215		0.0000	1.0000	4.26
55.5	8,630	280	0.0325	0.9675	4.26
56.5	6,776		0.0000	1.0000	4.12
57.5	3,532		0.0000	1.0000	4.12
58.5	1,496	111	0.0742	0.9258	4.12
59.5	1,385		0.0000	1.0000	3.82
60.5	1,385	114	0.0820	0.9180	3.82
61.5	250		0.0000	1.0000	3.51
62.5	250		0.0000	1.0000	3.51
63.5	250		0.0000	1.0000	3.51
64.5	250		0.0000	1.0000	3.51
65.5	250		0.0000	1.0000	3.51
66.5					3.51

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1954-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,554,555	50,717	0.0199	0.9801	100.00
0.5	2,406,347	152,137	0.0632	0.9368	98.01
1.5	2,087,016	122,525	0.0587	0.9413	91.82
2.5	1,778,472	100,085	0.0563	0.9437	86.43
3.5	1,597,190	78,533	0.0492	0.9508	81.56
4.5	1,400,074	46,493	0.0332	0.9668	77.55
5.5	1,229,694	70,795	0.0576	0.9424	74.98
6.5	1,080,816	59,198	0.0548	0.9452	70.66
7.5	904,715	57,896	0.0640	0.9360	66.79
8.5	650,328	42,747	0.0657	0.9343	62.52
9.5	560,734	45,549	0.0812	0.9188	58.41
10.5	478,211	34,227	0.0716	0.9284	53.66
11.5	416,356	24,031	0.0577	0.9423	49.82
12.5	412,835	20,240	0.0490	0.9510	46.95
13.5	385,734	24,789	0.0643	0.9357	44.65
14.5	373,154	66,689	0.1787	0.8213	41.78
15.5	323,088	28,171	0.0872	0.9128	34.31
16.5	293,182	28,229	0.0963	0.9037	31.32
17.5	270,500	25,007	0.0924	0.9076	28.30
18.5	240,545	17,893	0.0744	0.9256	25.69
19.5	225,117	19,040	0.0846	0.9154	23.78
20.5	203,342	13,652	0.0671	0.9329	21.76
21.5	189,502	15,425	0.0814	0.9186	20.30
22.5	182,818	11,156	0.0610	0.9390	18.65
23.5	165,811	9,139	0.0551	0.9449	17.51
24.5	153,885	14,522	0.0944	0.9056	16.55
25.5	131,092	16,290	0.1243	0.8757	14.99
26.5	109,615	2,811	0.0256	0.9744	13.12
27.5	105,297	8,677	0.0824	0.9176	12.79
28.5	88,655	11,023	0.1243	0.8757	11.73
29.5	83,108	8,830	0.1062	0.8938	10.27
30.5	78,799	6,660	0.0845	0.9155	9.18
31.5	74,991	7,605	0.1014	0.8986	8.41
32.5	72,670	6,170	0.0849	0.9151	7.55
33.5	66,547	6,080	0.0914	0.9086	6.91
34.5	59,679	4,333	0.0726	0.9274	6.28
35.5	58,677	5,109	0.0871	0.9129	5.83
36.5	51,475	2,240	0.0435	0.9565	5.32
37.5	46,476	4,922	0.1059	0.8941	5.09
38.5	38,028	1,712	0.0450	0.9550	4.55

UNITIL ENERGY SYSTEMS, INC.

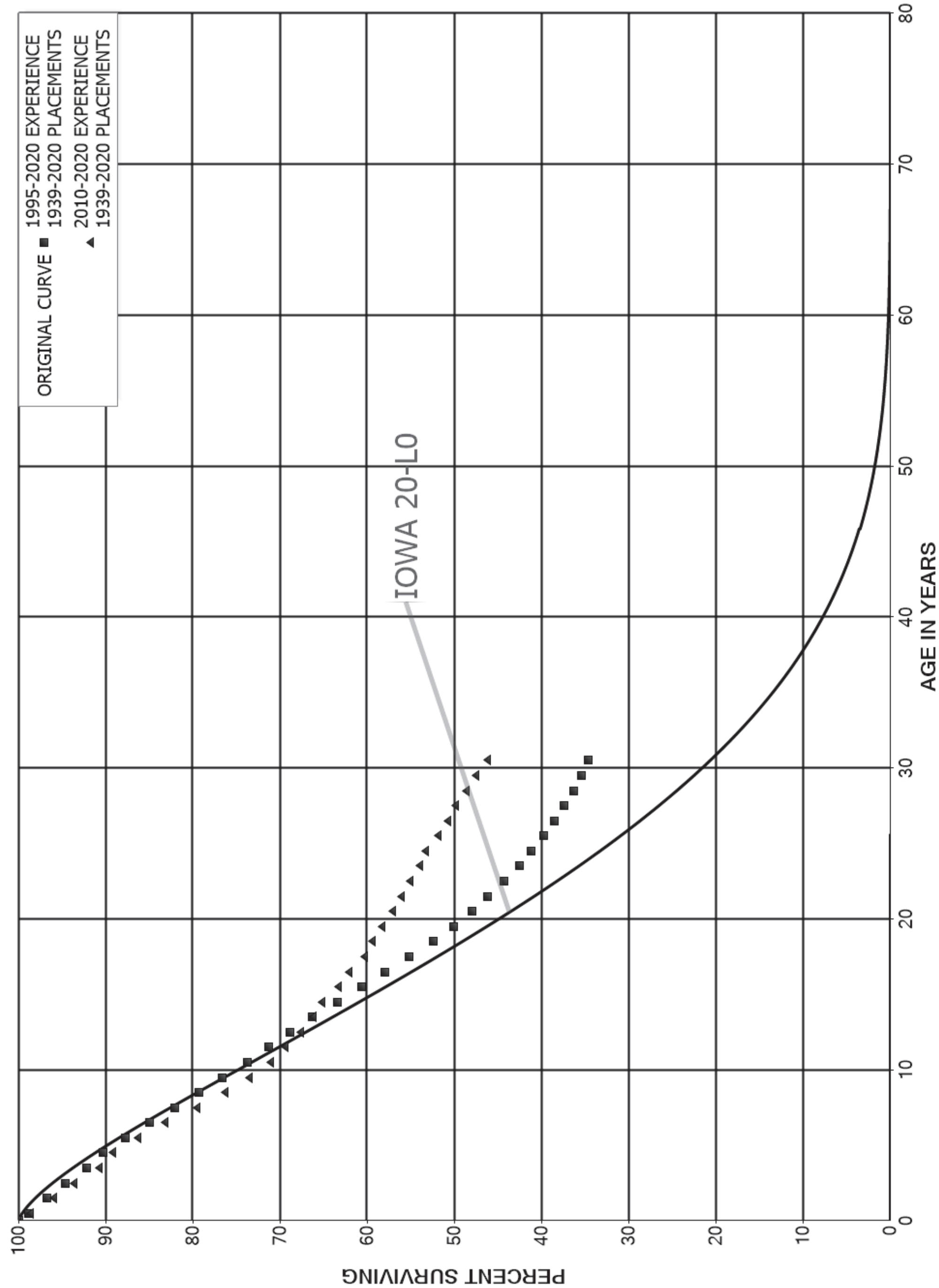
ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1954-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	35,997	2,537	0.0705	0.9295	4.34
40.5	30,351	1,911	0.0630	0.9370	4.04
41.5	26,776	692	0.0258	0.9742	3.78
42.5	29,002	306	0.0106	0.9894	3.69
43.5	27,736	1,310	0.0472	0.9528	3.65
44.5	26,141	2,774	0.1061	0.8939	3.47
45.5	25,305	1,180	0.0466	0.9534	3.11
46.5	25,471	480	0.0189	0.9811	2.96
47.5	27,107	1,435	0.0529	0.9471	2.90
48.5	24,274	986	0.0406	0.9594	2.75
49.5	22,834	1,580	0.0692	0.9308	2.64
50.5	20,901	683	0.0327	0.9673	2.46
51.5	18,039	389	0.0215	0.9785	2.38
52.5	14,040	242	0.0172	0.9828	2.33
53.5	11,840		0.0000	1.0000	2.29
54.5	9,965		0.0000	1.0000	2.29
55.5	8,630	280	0.0325	0.9675	2.29
56.5	6,776		0.0000	1.0000	2.21
57.5	3,532		0.0000	1.0000	2.21
58.5	1,496	111	0.0742	0.9258	2.21
59.5	1,385		0.0000	1.0000	2.05
60.5	1,385	114	0.0820	0.9180	2.05
61.5	250		0.0000	1.0000	1.88
62.5	250		0.0000	1.0000	1.88
63.5	250		0.0000	1.0000	1.88
64.5	250		0.0000	1.0000	1.88
65.5	250		0.0000	1.0000	1.88
66.5					1.88

UNITIL ENERGY SYSTEMS, INC.
ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES



UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1939-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,907,385	44,927	0.0115	0.9885	100.00
0.5	4,039,720	88,415	0.0219	0.9781	98.85
1.5	3,952,953	85,902	0.0217	0.9783	96.69
2.5	3,758,658	95,342	0.0254	0.9746	94.59
3.5	3,675,019	75,200	0.0205	0.9795	92.19
4.5	3,561,846	100,812	0.0283	0.9717	90.30
5.5	3,482,077	108,904	0.0313	0.9687	87.74
6.5	3,354,935	113,903	0.0340	0.9660	85.00
7.5	3,157,197	107,564	0.0341	0.9659	82.11
8.5	3,082,838	106,905	0.0347	0.9653	79.32
9.5	3,052,976	112,435	0.0368	0.9632	76.57
10.5	2,890,420	97,336	0.0337	0.9663	73.75
11.5	2,710,608	93,947	0.0347	0.9653	71.26
12.5	2,567,814	94,679	0.0369	0.9631	68.79
13.5	2,465,587	104,656	0.0424	0.9576	66.26
14.5	2,297,407	102,863	0.0448	0.9552	63.44
15.5	2,146,485	93,278	0.0435	0.9565	60.60
16.5	2,022,323	97,312	0.0481	0.9519	57.97
17.5	1,999,395	102,104	0.0511	0.9489	55.18
18.5	1,845,403	82,597	0.0448	0.9552	52.36
19.5	1,681,633	68,520	0.0407	0.9593	50.02
20.5	1,529,641	58,960	0.0385	0.9615	47.98
21.5	1,398,257	56,359	0.0403	0.9597	46.13
22.5	1,296,966	52,952	0.0408	0.9592	44.27
23.5	1,222,738	36,478	0.0298	0.9702	42.46
24.5	1,113,648	40,580	0.0364	0.9636	41.20
25.5	908,984	27,205	0.0299	0.9701	39.70
26.5	755,560	22,867	0.0303	0.9697	38.51
27.5	673,742	18,318	0.0272	0.9728	37.34
28.5	596,069	15,258	0.0256	0.9744	36.33
29.5	526,397	12,102	0.0230	0.9770	35.40
30.5	479,061	9,034	0.0189	0.9811	34.58
31.5	429,420	3,041	0.0071	0.9929	33.93
32.5	372,495	5,402	0.0145	0.9855	33.69
33.5	355,423	30,593	0.0861	0.9139	33.20
34.5	292,819	6,711	0.0229	0.9771	30.34
35.5	274,753	3,124	0.0114	0.9886	29.65
36.5	270,497	4,121	0.0152	0.9848	29.31
37.5	258,320	1,092	0.0042	0.9958	28.87
38.5	244,296	2,725	0.0112	0.9888	28.74

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1939-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	213,489	2,324	0.0109	0.9891	28.42
40.5	211,896	1,072	0.0051	0.9949	28.11
41.5	195,078	1,548	0.0079	0.9921	27.97
42.5	185,491	21,815	0.1176	0.8824	27.75
43.5	131,684	1,218	0.0092	0.9908	24.49
44.5	128,617	985	0.0077	0.9923	24.26
45.5	123,101	421	0.0034	0.9966	24.07
46.5	120,618	331	0.0027	0.9973	23.99
47.5	96,354	582	0.0060	0.9940	23.93
48.5	89,129	1,153	0.0129	0.9871	23.78
49.5	62,871	356	0.0057	0.9943	23.47
50.5	51,667	696	0.0135	0.9865	23.34
51.5	44,347	95	0.0021	0.9979	23.03
52.5	38,982	272	0.0070	0.9930	22.98
53.5	32,413	197	0.0061	0.9939	22.82
54.5	30,953		0.0000	1.0000	22.68
55.5	31,014	193	0.0062	0.9938	22.68
56.5	29,841	1,259	0.0422	0.9578	22.54
57.5	26,982	180	0.0067	0.9933	21.59
58.5	21,785		0.0000	1.0000	21.44
59.5	20,957		0.0000	1.0000	21.44
60.5	20,575	3,274	0.1591	0.8409	21.44
61.5	15,990		0.0000	1.0000	18.03
62.5	11,337	217	0.0192	0.9808	18.03
63.5	11,119	874	0.0786	0.9214	17.68
64.5	10,245		0.0000	1.0000	16.29
65.5	10,245		0.0000	1.0000	16.29
66.5	5,290		0.0000	1.0000	16.29
67.5	4,734		0.0000	1.0000	16.29
68.5	3,120	217	0.0697	0.9303	16.29
69.5	2,903		0.0000	1.0000	15.16
70.5	446		0.0000	1.0000	15.16
71.5	341		0.0000	1.0000	15.16
72.5	341		0.0000	1.0000	15.16
73.5	341		0.0000	1.0000	15.16
74.5	341		0.0000	1.0000	15.16
75.5	341		0.0000	1.0000	15.16
76.5	341		0.0000	1.0000	15.16
77.5	341		0.0000	1.0000	15.16
78.5	341		0.0000	1.0000	15.16

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1939-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	77		0.0000	1.0000	15.16
80.5	77		0.0000	1.0000	15.16
81.5					15.16

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1939-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,633,009	25,191	0.0154	0.9846	100.00
0.5	1,718,318	46,168	0.0269	0.9731	98.46
1.5	1,644,944	40,063	0.0244	0.9756	95.81
2.5	1,579,198	48,316	0.0306	0.9694	93.48
3.5	1,567,870	27,181	0.0173	0.9827	90.62
4.5	1,527,810	48,851	0.0320	0.9680	89.05
5.5	1,445,058	52,516	0.0363	0.9637	86.20
6.5	1,359,199	59,204	0.0436	0.9564	83.07
7.5	1,253,243	51,138	0.0408	0.9592	79.45
8.5	1,243,133	45,054	0.0362	0.9638	76.21
9.5	1,247,191	42,644	0.0342	0.9658	73.45
10.5	1,204,893	28,847	0.0239	0.9761	70.93
11.5	1,117,455	27,410	0.0245	0.9755	69.24
12.5	1,072,512	23,379	0.0218	0.9782	67.54
13.5	1,008,624	15,704	0.0156	0.9844	66.07
14.5	1,077,555	30,186	0.0280	0.9720	65.04
15.5	1,106,736	22,960	0.0207	0.9793	63.22
16.5	1,090,265	29,660	0.0272	0.9728	61.90
17.5	1,053,882	16,470	0.0156	0.9844	60.22
18.5	1,035,108	19,450	0.0188	0.9812	59.28
19.5	982,730	20,109	0.0205	0.9795	58.16
20.5	928,772	16,134	0.0174	0.9826	56.97
21.5	892,662	16,369	0.0183	0.9817	55.98
22.5	842,328	16,393	0.0195	0.9805	54.96
23.5	820,861	10,859	0.0132	0.9868	53.89
24.5	755,837	20,506	0.0271	0.9729	53.18
25.5	570,785	12,167	0.0213	0.9787	51.73
26.5	437,566	7,777	0.0178	0.9822	50.63
27.5	375,671	9,104	0.0242	0.9758	49.73
28.5	343,639	7,945	0.0231	0.9769	48.53
29.5	290,308	8,332	0.0287	0.9713	47.40
30.5	266,447	5,479	0.0206	0.9794	46.04
31.5	229,602	2,511	0.0109	0.9891	45.10
32.5	251,662	5,402	0.0215	0.9785	44.60
33.5	241,722	30,593	0.1266	0.8734	43.65
34.5	183,711	6,711	0.0365	0.9635	38.12
35.5	164,932	3,124	0.0189	0.9811	36.73
36.5	180,560	4,121	0.0228	0.9772	36.03
37.5	176,558	1,092	0.0062	0.9938	35.21
38.5	189,345	2,725	0.0144	0.9856	34.99

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1939-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	171,406	2,324	0.0136	0.9864	34.49
40.5	170,058	1,072	0.0063	0.9937	34.02
41.5	158,718	1,548	0.0098	0.9902	33.81
42.5	155,880	21,815	0.1399	0.8601	33.48
43.5	103,667	1,218	0.0117	0.9883	28.79
44.5	96,636	985	0.0102	0.9898	28.45
45.5	92,233	421	0.0046	0.9954	28.16
46.5	91,349	331	0.0036	0.9964	28.04
47.5	72,406	582	0.0080	0.9920	27.93
48.5	66,045	1,153	0.0175	0.9825	27.71
49.5	40,381	356	0.0088	0.9912	27.23
50.5	32,185	696	0.0216	0.9784	26.99
51.5	30,078	95	0.0032	0.9968	26.40
52.5	24,713	272	0.0110	0.9890	26.32
53.5	17,880	197	0.0110	0.9890	26.03
54.5	16,419		0.0000	1.0000	25.74
55.5	24,419	193	0.0079	0.9921	25.74
56.5	23,801	1,259	0.0529	0.9471	25.54
57.5	22,558	180	0.0080	0.9920	24.19
58.5	17,360		0.0000	1.0000	24.00
59.5	20,511		0.0000	1.0000	24.00
60.5	20,234	3,274	0.1618	0.8382	24.00
61.5	15,649		0.0000	1.0000	20.11
62.5	10,995	217	0.0198	0.9802	20.11
63.5	10,778	874	0.0811	0.9189	19.72
64.5	9,903		0.0000	1.0000	18.12
65.5	9,903		0.0000	1.0000	18.12
66.5	4,949		0.0000	1.0000	18.12
67.5	4,393		0.0000	1.0000	18.12
68.5	3,043	217	0.0715	0.9285	18.12
69.5	2,825		0.0000	1.0000	16.82
70.5	446		0.0000	1.0000	16.82
71.5	341		0.0000	1.0000	16.82
72.5	341		0.0000	1.0000	16.82
73.5	341		0.0000	1.0000	16.82
74.5	341		0.0000	1.0000	16.82
75.5	341		0.0000	1.0000	16.82
76.5	341		0.0000	1.0000	16.82
77.5	341		0.0000	1.0000	16.82
78.5	341		0.0000	1.0000	16.82

UNITIL ENERGY SYSTEMS, INC.

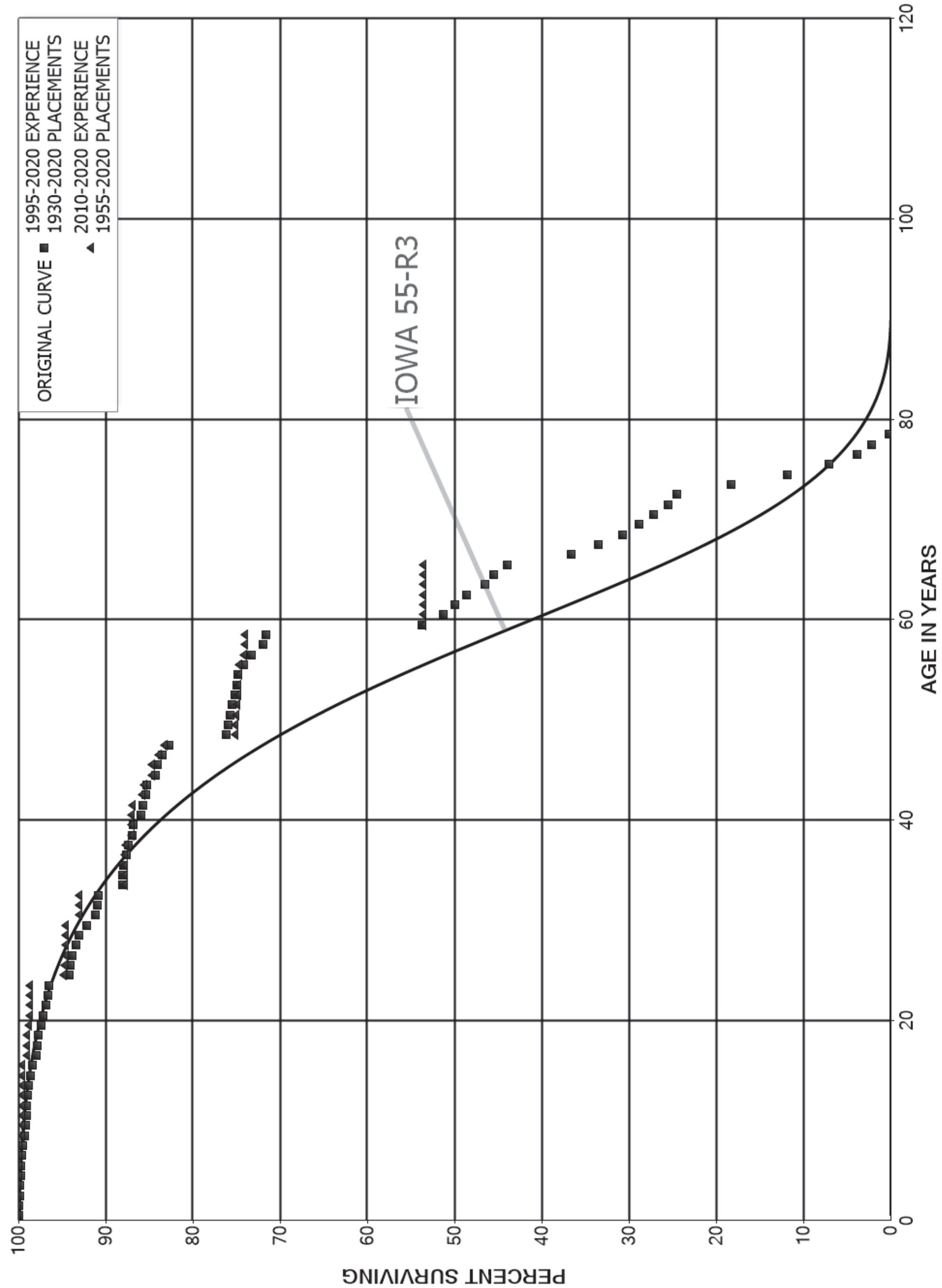
ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1939-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	77		0.0000	1.0000	16.82
80.5	77		0.0000	1.0000	16.82
81.5					16.82

UNITIL ENERGY SYSTEMS, INC.
ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1930-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	17,032,322	628	0.0000	1.0000	100.00
0.5	2,242,045	796	0.0004	0.9996	100.00
1.5	2,310,156	2,082	0.0009	0.9991	99.96
2.5	2,328,673	926	0.0004	0.9996	99.87
3.5	2,069,998	1,676	0.0008	0.9992	99.83
4.5	2,139,136	1,368	0.0006	0.9994	99.75
5.5	2,209,404	1,436	0.0007	0.9993	99.69
6.5	2,129,795	1,697	0.0008	0.9992	99.62
7.5	2,261,514	5,239	0.0023	0.9977	99.54
8.5	2,237,012	1,968	0.0009	0.9991	99.31
9.5	2,209,072	2,789	0.0013	0.9987	99.22
10.5	2,223,542	1,970	0.0009	0.9991	99.10
11.5	2,107,932	1,676	0.0008	0.9992	99.01
12.5	1,863,842	1,892	0.0010	0.9990	98.93
13.5	1,894,581	3,107	0.0016	0.9984	98.83
14.5	2,235,298	5,662	0.0025	0.9975	98.67
15.5	2,236,482	11,429	0.0051	0.9949	98.42
16.5	2,161,701	2,088	0.0010	0.9990	97.92
17.5	2,151,316	2,085	0.0010	0.9990	97.82
18.5	2,138,464	6,986	0.0033	0.9967	97.73
19.5	2,116,450	5,034	0.0024	0.9976	97.41
20.5	2,059,990	6,202	0.0030	0.9970	97.18
21.5	2,107,785	5,108	0.0024	0.9976	96.88
22.5	1,986,398	3,631	0.0018	0.9982	96.65
23.5	1,755,683	42,482	0.0242	0.9758	96.47
24.5	1,643,698	1,290	0.0008	0.9992	94.14
25.5	1,553,735	4,438	0.0029	0.9971	94.06
26.5	1,396,343	6,008	0.0043	0.9957	93.80
27.5	1,295,654	4,560	0.0035	0.9965	93.39
28.5	1,847,712	17,816	0.0096	0.9904	93.06
29.5	1,807,335	20,306	0.0112	0.9888	92.17
30.5	1,735,820	3,928	0.0023	0.9977	91.13
31.5	1,635,884	2,443	0.0015	0.9985	90.92
32.5	1,586,477	47,370	0.0299	0.9701	90.79
33.5	1,394,098	1,039	0.0007	0.9993	88.08
34.5	1,359,259	1,036	0.0008	0.9992	88.01
35.5	1,307,210	5,590	0.0043	0.9957	87.95
36.5	1,278,602	3,341	0.0026	0.9974	87.57
37.5	1,269,759	5,476	0.0043	0.9957	87.34
38.5	1,252,117	2,114	0.0017	0.9983	86.96

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1930-2020 EXPERIENCE BAND 1995-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,387,919	13,520	0.0097	0.9903	86.82
40.5	1,006,968	3,301	0.0033	0.9967	85.97
41.5	953,978	2,807	0.0029	0.9971	85.69
42.5	902,380	1,645	0.0018	0.9982	85.44
43.5	900,628	10,190	0.0113	0.9887	85.28
44.5	891,022	2,095	0.0024	0.9976	84.32
45.5	894,928	7,027	0.0079	0.9921	84.12
46.5	881,625	8,126	0.0092	0.9908	83.46
47.5	822,883	64,935	0.0789	0.9211	82.69
48.5	750,353	1,627	0.0022	0.9978	76.16
49.5	747,588	3,016	0.0040	0.9960	76.00
50.5	744,977	1,787	0.0024	0.9976	75.69
51.5	745,065	3,579	0.0048	0.9952	75.51
52.5	743,370	1,949	0.0026	0.9974	75.15
53.5	740,533	1,371	0.0019	0.9981	74.95
54.5	229,172	2,011	0.0088	0.9912	74.81
55.5	227,892	2,616	0.0115	0.9885	74.15
56.5	226,769	4,296	0.0189	0.9811	73.30
57.5	223,482	902	0.0040	0.9960	71.92
58.5	173,725	43,513	0.2505	0.7495	71.62
59.5	137,782	6,022	0.0437	0.9563	53.69
60.5	137,908	3,697	0.0268	0.9732	51.34
61.5	139,143	3,608	0.0259	0.9741	49.96
62.5	138,763	6,197	0.0447	0.9553	48.67
63.5	138,171	2,983	0.0216	0.9784	46.49
64.5	137,577	4,825	0.0351	0.9649	45.49
65.5	23,043	3,801	0.1650	0.8350	43.89
66.5	19,242	1,666	0.0866	0.9134	36.65
67.5	17,575	1,440	0.0819	0.9181	33.48
68.5	16,135	1,005	0.0623	0.9377	30.74
69.5	15,131	856	0.0566	0.9434	28.82
70.5	14,275	870	0.0609	0.9391	27.19
71.5	13,405	565	0.0421	0.9579	25.53
72.5	12,840	3,254	0.2534	0.7466	24.46
73.5	9,586	3,394	0.3540	0.6460	18.26
74.5	6,193	2,473	0.3993	0.6007	11.80
75.5	3,720	1,717	0.4614	0.5386	7.09
76.5	2,004	888	0.4433	0.5567	3.82
77.5	1,115	1,026	0.9201	0.0799	2.12
78.5	89	89	1.0000		0.17
79.5					

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1955-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	15,694,899		0.0000	1.0000	100.00
0.5	859,644		0.0000	1.0000	100.00
1.5	1,100,967	759	0.0007	0.9993	100.00
2.5	1,133,536		0.0000	1.0000	99.93
3.5	907,812	901	0.0010	0.9990	99.93
4.5	929,454	7	0.0000	1.0000	99.83
5.5	1,022,883		0.0000	1.0000	99.83
6.5	841,824		0.0000	1.0000	99.83
7.5	836,867	3,008	0.0036	0.9964	99.83
8.5	793,084		0.0000	1.0000	99.47
9.5	769,899		0.0000	1.0000	99.47
10.5	767,310		0.0000	1.0000	99.47
11.5	781,799		0.0000	1.0000	99.47
12.5	738,302		0.0000	1.0000	99.47
13.5	782,632		0.0000	1.0000	99.47
14.5	836,694		0.0000	1.0000	99.47
15.5	952,206	4,530	0.0048	0.9952	99.47
16.5	925,025		0.0000	1.0000	99.00
17.5	935,390		0.0000	1.0000	99.00
18.5	945,406	2,093	0.0022	0.9978	99.00
19.5	1,021,814	1,231	0.0012	0.9988	98.78
20.5	1,059,915		0.0000	1.0000	98.66
21.5	1,160,514		0.0000	1.0000	98.66
22.5	1,172,960		0.0000	1.0000	98.66
23.5	977,758	39,550	0.0404	0.9596	98.66
24.5	913,212	8	0.0000	1.0000	94.67
25.5	827,368	1,708	0.0021	0.9979	94.67
26.5	671,505		0.0000	1.0000	94.47
27.5	599,649		0.0000	1.0000	94.47
28.5	642,220	20	0.0000	1.0000	94.47
29.5	986,295	15,920	0.0161	0.9839	94.47
30.5	967,324		0.0000	1.0000	92.95
31.5	925,647	123	0.0001	0.9999	92.95
32.5	820,866	46,237	0.0563	0.9437	92.93
33.5	631,711	8	0.0000	1.0000	87.70
34.5	597,119	17	0.0000	1.0000	87.70
35.5	551,473	70	0.0001	0.9999	87.70
36.5	578,290	746	0.0013	0.9987	87.68
37.5	583,437	3,814	0.0065	0.9935	87.57
38.5	566,806		0.0000	1.0000	87.00

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1955-2020 EXPERIENCE BAND 2010-2020

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	558,597	10	0.0000	1.0000	87.00
40.5	189,902	320	0.0017	0.9983	87.00
41.5	144,481	1,826	0.0126	0.9874	86.85
42.5	93,964	252	0.0027	0.9973	85.75
43.5	668,325	6,850	0.0102	0.9898	85.52
44.5	661,939	494	0.0007	0.9993	84.65
45.5	662,199	5,810	0.0088	0.9912	84.58
46.5	650,583	4,818	0.0074	0.9926	83.84
47.5	650,752	63,581	0.0977	0.9023	83.22
48.5	574,310		0.0000	1.0000	75.09
49.5	573,197	754	0.0013	0.9987	75.09
50.5	572,680	1,206	0.0021	0.9979	74.99
51.5	572,918	1,164	0.0020	0.9980	74.83
52.5	571,911		0.0000	1.0000	74.68
53.5	569,430	127	0.0002	0.9998	74.68
54.5	209,652	237	0.0011	0.9989	74.66
55.5	208,951	1,444	0.0069	0.9931	74.58
56.5	207,507	157	0.0008	0.9992	74.06
57.5	207,350	54	0.0003	0.9997	74.01
58.5	151,734	42,025	0.2770	0.7230	73.99
59.5	109,709		0.0000	1.0000	53.50
60.5	109,709		0.0000	1.0000	53.50
61.5	109,709		0.0000	1.0000	53.50
62.5	109,709		0.0000	1.0000	53.50
63.5	109,709		0.0000	1.0000	53.50
64.5	109,709		0.0000	1.0000	53.50
65.5					53.50

PART VIII. NET SALVAGE STATISTICS

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1995	4,528	3,166	70		0	3,166-	70-
1996	104		0		0		0
1997	7,005	3,488	50	751	11	2,737-	39-
1998							
1999	39,095	28,110	72	3,824	10	24,286-	62-
2000	3,000	1,872	62	250	8	1,622-	54-
2001	3,500	2,903	83	763	22	2,140-	61-
2002	1,486	1,078	73	115	8	963-	65-
2003							
2004							
2005							
2006							
2007							
2008							
2009							
2010							
2011							
2012							
2013							
2014							
2015							
2016							
2017							
2018							
2019							
2020							
TOTAL	58,718	40,617	69	5,703	10	34,914-	59-
THREE-YEAR MOVING AVERAGES							
95-97	3,879	2,218	57	250	6	1,968-	51-
96-98	2,370	1,163	49	250	11	912-	39-
97-99	15,367	10,533	69	1,525	10	9,008-	59-
98-00	14,032	9,994	71	1,358	10	8,636-	62-
99-01	15,198	10,962	72	1,612	11	9,349-	62-
00-02	2,662	1,951	73	376	14	1,575-	59-
01-03	1,662	1,327	80	293	18	1,034-	62-
02-04	495	359	73	38	8	321-	65-
03-05							
04-06							
05-07							
06-08							

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
07-09							
08-10							
09-11							
10-12							
11-13							
12-14							
13-15							
14-16							
15-17							
16-18							
17-19							
18-20							
FIVE-YEAR AVERAGE							
16-20							

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 362.00 STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1995	79,290	42,685	54	16,596	21	26,089-	33-
1996	161,461	94,743	59	21,926	14	72,817-	45-
1997	152,509	85,123	56	14,677	10	70,446-	46-
1998	47,517	39,154	82	7,087	15	32,067-	67-
1999	72,476	52,380	72	7,748	11	44,632-	62-
2000	107,961	67,894	63	9,155	8	58,739-	54-
2001	66,111	34,300	52	10,945	17	23,355-	35-
2002	176,062	139,408	79	12,742	7	126,666-	72-
2003	52,126	42,721	82	3,304	6	39,417-	76-
2004	75,850	68,284	90	3,452	5	64,832-	85-
2005	26,444	29,441	111	931	4	28,510-	108-
2006	122,758	68,190	56	4,332	4	63,858-	52-
2007	195,446	157,706	81	13,957	7	143,749-	74-
2008	61,843	7,903	13	450	1	7,453-	12-
2009	102,491	15,082	15		0	15,082-	15-
2010	63,334	25,387	40	678	1	24,709-	39-
2011	14,188	4,014	28		0	4,014-	28-
2012	138,609	148,497	107	1,452	1	147,044-	106-
2013	19,974	3,131	16		0	3,131-	16-
2014	89,596	10,488	12	83	0	10,405-	12-
2015	98,247	19,844	20		0	19,844-	20-
2016	180,145	36,398	20	385	0	36,012-	20-
2017	117,448	5,888	5		0	5,888-	5-
2018	75,409	52,152	69		0	52,152-	69-
2019	150,096	15,687	10		0	15,687-	10-
2020	1,380,497	860,945	62	83	0	860,862-	62-
TOTAL	3,827,889	2,127,444	56	129,984	3	1,997,460-	52-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
95-97	131,087	74,184	57	17,733	14	56,451-	43-
96-98	120,496	73,007	61	14,563	12	58,443-	49-
97-99	90,834	58,886	65	9,837	11	49,048-	54-
98-00	75,985	53,143	70	7,997	11	45,146-	59-
99-01	82,183	51,525	63	9,283	11	42,242-	51-
00-02	116,711	80,534	69	10,947	9	69,587-	60-
01-03	98,100	72,143	74	8,997	9	63,146-	64-
02-04	101,346	83,471	82	6,499	6	76,972-	76-
03-05	51,473	46,815	91	2,562	5	44,253-	86-
04-06	75,017	55,305	74	2,905	4	52,400-	70-
05-07	114,883	85,112	74	6,407	6	78,706-	69-
06-08	126,682	77,933	62	6,246	5	71,687-	57-

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 362.00 STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
07-09	119,927	60,230	50	4,802	4	55,428-	46-
08-10	75,889	16,124	21	376	0	15,748-	21-
09-11	60,004	14,828	25	226	0	14,602-	24-
10-12	72,044	59,299	82	710	1	58,589-	81-
11-13	57,590	51,880	90	484	1	51,396-	89-
12-14	82,726	54,039	65	512	1	53,527-	65-
13-15	69,272	11,154	16	28	0	11,127-	16-
14-16	122,663	22,243	18	156	0	22,087-	18-
15-17	131,947	20,710	16	128	0	20,581-	16-
16-18	124,334	31,479	25	128	0	31,351-	25-
17-19	114,318	24,575	21		0	24,575-	21-
18-20	535,334	309,595	58	28	0	309,567-	58-
FIVE-YEAR AVERAGE							
16-20	380,719	194,214	51	94	0	194,120-	51-

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1995	98,631	53,923	55	20,117	20	33,806-	34-
1996	130,620	70,685	54	21,214	16	49,471-	38-
1997	132,246	67,382	51	13,888	11	53,494-	40-
1998	112,808	70,888	63	16,363	15	54,525-	48-
1999	157,884	116,125	74	23,559	15	92,566-	59-
2000	141,717	94,430	67	13,560	10	80,870-	57-
2001	206,613	167,045	81	25,749	12	141,296-	68-
2002	136,447	118,772	87	9,048	7	109,724-	80-
2003	178,664	140,349	79	12,041	7	128,308-	72-
2004	166,758	156,689	94	5,742	3	150,947-	91-
2005	171,500	186,931	109	5,750	3	181,181-	106-
2006	232,727	186,345	80	16,257	7	170,088-	73-
2007	258,398	209,102	81	14,634	6	194,468-	75-
2008	195,506	226,091	116	6,152	3	219,939-	112-
2009	245,951	384,764	156	7,897	3	376,867-	153-
2010	290,882	447,959	154	8,021	3	439,938-	151-
2011	259,343	493,559	190	2,872	1	490,687-	189-
2012	381,241	275,206	72	4,154	1	271,052-	71-
2013	520,923	377,196	72	6,541	1	370,655-	71-
2014	515,504	358,855	70	4,778	1	354,076-	69-
2015	386,259	280,538	73	6,013	2	274,525-	71-
2016	348,903	256,752	74	4,862	1	251,890-	72-
2017	302,782	154,558	51	3,388	1	151,170-	50-
2018	448,980	598,930	133	4,607	1	594,324-	132-
2019	745,124	308,634	41	6,708	1	301,926-	41-
2020	639,678	677,404	106	6,556	1	670,848-	105-
TOTAL	7,406,088	6,479,113	87	270,472	4	6,208,642-	84-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
95-97	120,499	63,997	53	18,406	15	45,590-	38-
96-98	125,225	69,652	56	17,155	14	52,497-	42-
97-99	134,313	84,798	63	17,937	13	66,862-	50-
98-00	137,470	93,814	68	17,827	13	75,987-	55-
99-01	168,738	125,867	75	20,956	12	104,911-	62-
00-02	161,592	126,749	78	16,119	10	110,630-	68-
01-03	173,908	142,055	82	15,613	9	126,443-	73-
02-04	160,623	138,603	86	8,944	6	129,660-	81-
03-05	172,307	161,323	94	7,844	5	153,479-	89-
04-06	190,328	176,655	93	9,250	5	167,405-	88-
05-07	220,875	194,126	88	12,214	6	181,912-	82-
06-08	228,877	207,179	91	12,348	5	194,832-	85-

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
07-09	233,285	273,319	117	9,561	4	263,758-	113-
08-10	244,113	352,938	145	7,357	3	345,581-	142-
09-11	265,392	442,094	167	6,263	2	435,831-	164-
10-12	310,489	405,575	131	5,016	2	400,559-	129-
11-13	387,169	381,987	99	4,522	1	377,465-	97-
12-14	472,556	337,086	71	5,158	1	331,928-	70-
13-15	474,229	338,863	71	5,777	1	333,086-	70-
14-16	416,889	298,715	72	5,218	1	293,497-	70-
15-17	345,981	230,616	67	4,754	1	225,862-	65-
16-18	366,888	336,747	92	4,286	1	332,461-	91-
17-19	498,962	354,041	71	4,901	1	349,140-	70-
18-20	611,261	528,323	86	5,957	1	522,366-	85-
FIVE-YEAR AVERAGE							
16-20	497,093	399,256	80	5,224	1	394,032-	79-

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1995	95,897	55,920	58	17,324	18	38,596-	40-
1996	168,054	93,264	55	25,941	15	67,323-	40-
1997	197,378	105,706	54	19,788	10	85,918-	44-
1998	160,490	102,543	64	23,316	15	79,227-	49-
1999	152,262	111,263	73	20,455	13	90,808-	60-
2000	245,965	163,494	66	23,419	10	140,075-	57-
2001	185,665	150,221	81	23,641	13	126,580-	68-
2002	201,762	174,133	86	13,494	7	160,639-	80-
2003	428,872	336,032	78	29,006	7	307,026-	72-
2004	276,004	256,563	93	10,284	4	246,279-	89-
2005	381,854	405,680	106	12,042	3	393,638-	103-
2006	484,573	381,356	79	32,912	7	348,444-	72-
2007	584,934	473,227	81	33,175	6	440,052-	75-
2008	738,382	455,089	62	12,624	2	442,465-	60-
2009	504,864	440,570	87	16,836	3	423,734-	84-
2010	850,735	521,471	61	23,118	3	498,353-	59-
2011	582,544	853,510	147	4,119	1	849,392-	146-
2012	750,239	459,331	61	9,299	1	450,031-	60-
2013	938,405	439,517	47	14,654	2	424,862-	45-
2014	637,176	364,179	57	9,219	1	354,960-	56-
2015	690,463	261,557	38	18,264	3	243,293-	35-
2016	701,357	318,438	45	15,453	2	302,985-	43-
2017	511,652	239,210	47	5,553	1	233,658-	46-
2018	704,772	587,509	83	11,454	2	576,055-	82-
2019	777,474	527,690	68	11,516	1	516,174-	66-
2020	1,086,410	998,041	92	22,401	2	975,640-	90-
TOTAL	13,038,183	9,275,514	71	459,306	4	8,816,207-	68-

THREE-YEAR MOVING AVERAGES

95-97	153,776	84,963	55	21,018	14	63,946-	42-
96-98	175,307	100,504	57	23,015	13	77,489-	44-
97-99	170,043	106,504	63	21,186	12	85,318-	50-
98-00	186,239	125,767	68	22,397	12	103,370-	56-
99-01	194,631	141,659	73	22,505	12	119,154-	61-
00-02	211,131	162,616	77	20,185	10	142,431-	67-
01-03	272,100	220,129	81	22,047	8	198,082-	73-
02-04	302,213	255,576	85	17,595	6	237,981-	79-
03-05	362,243	332,758	92	17,111	5	315,648-	87-
04-06	380,810	347,866	91	18,413	5	329,454-	87-
05-07	483,787	420,088	87	26,043	5	394,045-	81-
06-08	602,630	436,557	72	26,237	4	410,320-	68-

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
07-09	609,393	456,295	75	20,878	3	435,417-	71-
08-10	697,994	472,377	68	17,526	3	454,851-	65-
09-11	646,048	605,184	94	14,691	2	590,493-	91-
10-12	727,839	611,437	84	12,179	2	599,259-	82-
11-13	757,063	584,119	77	9,357	1	574,762-	76-
12-14	775,273	421,009	54	11,057	1	409,951-	53-
13-15	755,348	355,084	47	14,045	2	341,039-	45-
14-16	676,332	314,725	47	14,312	2	300,413-	44-
15-17	634,491	273,069	43	13,090	2	259,979-	41-
16-18	639,260	381,719	60	10,820	2	370,899-	58-
17-19	664,633	451,470	68	9,508	1	441,962-	66-
18-20	856,219	704,413	82	15,124	2	689,289-	81-
FIVE-YEAR AVERAGE							
16-20	756,333	534,178	71	13,275	2	520,902-	69-

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 366.00 UNDERGROUND CONDUIT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1995	817	572	70	87	11	485-	59-
1996	516	305	59	69	13	236-	46-
1997	2,328	1,372	59	210	9	1,162-	50-
1998	1,100	1,074	98	167	15	907-	82-
1999	2,832	2,036	72	277	10	1,759-	62-
2000	829	517	62	69	8	448-	54-
2001	1,012	840	83	221	22	619-	61-
2002	375	440	117	16	4	424-	113-
2003	2,500	2,163	87	145	6	2,018-	81-
2004	2,593	2,298	89	128	5	2,170-	84-
2005	411	514	125	19	5	495-	120-
2006	5,808	2,952	51	166	3	2,786-	48-
2007	2,699	2,159	80	163	6	1,996-	74-
2008	43,243	470	1	2	0	468-	1-
2009	117	1,329			0	1,329-	
2010	5,895	2,044	35	157	3	1,887-	32-
2011	4,761	7,411	156	272	6	7,138-	150-
2012	4,038	246	6	11	0	235-	6-
2013	1,990	543	27	96	5	447-	22-
2014	13,438	1,169	9	5	0	1,165-	9-
2015	11,159	4,019	36	158	1	3,861-	35-
2016	6,337	465	7		0	465-	7-
2017	2,274	101	4		0	101-	4-
2018	4,292	2,227	52		0	2,227-	52-
2019	4,816	7,292	151	14	0	7,278-	151-
2020	7,099	11,258	159	71	1	11,187-	158-
TOTAL	133,281	55,815	42	2,524	2	53,291-	40-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
95-97	1,220	750	61	122	10	628-	51-
96-98	1,315	917	70	149	11	768-	58-
97-99	2,087	1,494	72	218	10	1,276-	61-
98-00	1,587	1,209	76	171	11	1,038-	65-
99-01	1,558	1,131	73	189	12	942-	60-
00-02	739	599	81	102	14	497-	67-
01-03	1,296	1,148	89	127	10	1,020-	79-
02-04	1,823	1,634	90	96	5	1,537-	84-
03-05	1,835	1,658	90	97	5	1,561-	85-
04-06	2,937	1,921	65	104	4	1,817-	62-
05-07	2,973	1,875	63	116	4	1,759-	59-
06-08	17,250	1,860	11	110	1	1,750-	10-

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 366.00 UNDERGROUND CONDUIT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES							
07-09	15,353	1,319	9	55	0	1,264-	8-
08-10	16,418	1,281	8	53	0	1,228-	7-
09-11	3,591	3,594	100	143	4	3,451-	96-
10-12	4,898	3,233	66	147	3	3,087-	63-
11-13	3,596	2,733	76	126	4	2,607-	72-
12-14	6,489	653	10	37	1	615-	9-
13-15	8,863	1,910	22	86	1	1,824-	21-
14-16	10,312	1,884	18	54	1	1,830-	18-
15-17	6,590	1,528	23	53	1	1,475-	22-
16-18	4,301	931	22		0	931-	22-
17-19	3,794	3,207	85	5	0	3,202-	84-
18-20	5,402	6,926	128	28	1	6,897-	128-
FIVE-YEAR AVERAGE							
16-20	4,964	4,269	86	17	0	4,251-	86-

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1995	28,102	18,394	65	3,791	13	14,603-	52-
1996	48,967	28,609	58	6,721	14	21,888-	45-
1997	53,450	31,347	59	4,862	9	26,485-	50-
1998	12,644	8,759	69	1,851	15	6,908-	55-
1999	20,580	14,918	72	2,389	12	12,529-	61-
2000	28,656	19,171	67	2,765	10	16,406-	57-
2001	37,488	30,572	82	5,843	16	24,729-	66-
2002	13,577	11,651	86	913	7	10,738-	79-
2003	45,126	38,324	85	2,702	6	35,622-	79-
2004	35,850	33,316	93	1,339	4	31,977-	89-
2005	30,362	32,929	108	1,006	3	31,923-	105-
2006	58,644	34,821	59	2,386	4	32,435-	55-
2007	64,826	52,230	81	3,767	6	48,463-	75-
2008	36,465	26,909	74	469	1	26,440-	73-
2009	26,144	31,580	121	1,645	6	29,935-	115-
2010	61,348	44,208	72	7,076	12	37,132-	61-
2011	47,895	45,120	94	3,493	7	41,627-	87-
2012	44,245	16,617	38	338	1	16,278-	37-
2013	84,284	28,370	34	8,856	11	19,515-	23-
2014	63,234	20,329	32	1,427	2	18,901-	30-
2015	170,183	27,102	16	8,010	5	19,092-	11-
2016	88,835	16,626	19	8,084	9	8,542-	10-
2017	101,085	33,020	33	3,292	3	29,728-	29-
2018	93,582	81,626	87	785	1	80,841-	86-
2019	72,624	70,708	97	115	0	70,593-	97-
2020	93,997	91,504	97	4,747	5	86,757-	92-
TOTAL	1,462,192	888,760	61	88,673	6	800,086-	55-

THREE-YEAR MOVING AVERAGES

95-97	43,506	26,117	60	5,125	12	20,992-	48-
96-98	38,354	22,905	60	4,478	12	18,427-	48-
97-99	28,891	18,341	63	3,034	11	15,307-	53-
98-00	20,627	14,283	69	2,335	11	11,948-	58-
99-01	28,908	21,554	75	3,666	13	17,888-	62-
00-02	26,574	20,465	77	3,174	12	17,291-	65-
01-03	32,064	26,849	84	3,153	10	23,696-	74-
02-04	31,518	27,764	88	1,651	5	26,112-	83-
03-05	37,113	34,856	94	1,682	5	33,174-	89-
04-06	41,619	33,689	81	1,577	4	32,112-	77-
05-07	51,277	39,993	78	2,386	5	37,607-	73-
06-08	53,312	37,987	71	2,207	4	35,779-	67-

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
07-09	42,478	36,906	87	1,960	5	34,946-	82-
08-10	41,319	34,232	83	3,063	7	31,169-	75-
09-11	45,129	40,303	89	4,071	9	36,231-	80-
10-12	51,163	35,315	69	3,636	7	31,679-	62-
11-13	58,808	30,036	51	4,229	7	25,807-	44-
12-14	63,921	21,772	34	3,541	6	18,232-	29-
13-15	105,900	25,267	24	6,098	6	19,169-	18-
14-16	107,417	21,353	20	5,841	5	15,512-	14-
15-17	120,034	25,583	21	6,462	5	19,121-	16-
16-18	94,500	43,757	46	4,054	4	39,703-	42-
17-19	89,097	61,785	69	1,398	2	60,387-	68-
18-20	86,734	81,279	94	1,882	2	79,397-	92-
FIVE-YEAR AVERAGE							
16-20	90,024	58,697	65	3,405	4	55,292-	61-

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 368.00 LINE TRANSFORMERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1995	41,370		0	4,127	10	4,127	10
1996	26,762		0	3,163	12	3,163	12
1997	35,687		0	461	1	461	1
1998	16,370		0		0		0
1999	101,335		0		0		0
2000	128,889		0		0		0
2001	134,450		0		0		0
2002	215,321	43,565	20		0	43,565-	20-
2003	150,610	38,143	25		0	38,143-	25-
2004	144,809	59,420	41		0	59,420-	41-
2005	221,280	65,418	30		0	65,418-	30-
2006	218,771	48,027	22		0	48,027-	22-
2007	253,473	44,958	18		0	44,958-	18-
2008	35,606		0		0		0
2009	460,350	80,492	17	51,736	11	28,756-	6-
2010	270,087	179,294	66	11,490	4	167,804-	62-
2011	54,065	293	1		0	293-	1-
2012	82,001	54,457	66		0	54,457-	66-
2013	294,523	71,355	24		0	71,355-	24-
2014	378,987	49,499	13		0	49,499-	13-
2015	112,053	89,442	80		0	89,442-	80-
2016	298,373	111,182	37		0	111,182-	37-
2017	292,212	8,560	3	1	0	8,560-	3-
2018	5,449	13,420	246		0	13,420-	246-
2019	754,594		0		0		0
2020	559,611	47,138	8		0	47,138-	8-
TOTAL	5,287,037	1,004,663	19	70,978	1	933,685-	18-

THREE-YEAR MOVING AVERAGES

95-97	34,606		0	2,584	7	2,584	7
96-98	26,273		0	1,208	5	1,208	5
97-99	51,131		0	154	0	154	0
98-00	82,198		0		0		0
99-01	121,558		0		0		0
00-02	159,553	14,522	9		0	14,522-	9-
01-03	166,794	27,236	16		0	27,236-	16-
02-04	170,247	47,043	28		0	47,043-	28-
03-05	172,233	54,327	32		0	54,327-	32-
04-06	194,953	57,622	30		0	57,622-	30-
05-07	231,175	52,801	23		0	52,801-	23-
06-08	169,283	30,995	18		0	30,995-	18-

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 368.00 LINE TRANSFORMERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
07-09	249,810	41,817	17	17,245	7	24,571-	10-
08-10	255,348	86,595	34	21,075	8	65,520-	26-
09-11	261,501	86,693	33	21,075	8	65,618-	25-
10-12	135,384	78,015	58	3,830	3	74,185-	55-
11-13	143,530	42,035	29		0	42,035-	29-
12-14	251,837	58,437	23		0	58,437-	23-
13-15	261,854	70,098	27		0	70,098-	27-
14-16	263,138	83,374	32		0	83,374-	32-
15-17	234,213	69,728	30		0	69,728-	30-
16-18	198,678	44,387	22		0	44,387-	22-
17-19	350,751	7,327	2		0	7,327-	2-
18-20	439,884	20,186	5		0	20,186-	5-
FIVE-YEAR AVERAGE							
16-20	382,048	36,060	9		0	36,060-	9-

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 368.01 LINE TRANSFORMER INSTALLATIONS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1999	25,554		0		0		0
2000	63,233		0		0		0
2001	53,116		0		0		0
2002							
2003	115,603		0		0		0
2004	121,531		0		0		0
2005	152,013		0		0		0
2006	173,617		0		0		0
2007	177,666		0		0		0
2008	52,676	34,528	66		0	34,528-	66-
2009	417,990	747	0		0	747-	0
2010	177,794	27,765	16		0	27,765-	16-
2011	56,808	3,282-	6-		0	3,282	6
2012	59,262	8,117	14		0	8,117-	14-
2013	156,085	7,748	5		0	7,748-	5-
2014	249,682	1,235	0		0	1,235-	0
2015	43	83	191		0	83-	191-
2016	42,638	621	1		0	621-	1-
2017	166,950	434	0		0	434-	0
2018	5,354	33	1		0	33-	1-
2019	317,618		0	51	0	51	0
2020	247,939	272	0	7	0	265-	0
TOTAL	2,833,174	78,301	3	58	0	78,243-	3-

THREE-YEAR MOVING AVERAGES

99-01	47,301		0		0		0
00-02	38,783		0		0		0
01-03	56,240		0		0		0
02-04	79,045		0		0		0
03-05	129,716		0		0		0
04-06	149,054		0		0		0
05-07	167,765		0		0		0
06-08	134,653	11,509	9		0	11,509-	9-
07-09	216,111	11,758	5		0	11,758-	5-
08-10	216,153	21,013	10		0	21,013-	10-
09-11	217,531	8,410	4		0	8,410-	4-
10-12	97,955	10,867	11		0	10,867-	11-
11-13	90,719	4,194	5		0	4,194-	5-
12-14	155,010	5,700	4		0	5,700-	4-
13-15	135,270	3,022	2		0	3,022-	2-
14-16	97,454	646	1		0	646-	1-

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 368.01 LINE TRANSFORMER INSTALLATIONS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
15-17	69,877	379	1		0	379-	1-
16-18	71,648	363	1		0	363-	1-
17-19	163,308	156	0	17	0	139-	0
18-20	190,304	102	0	19	0	83-	0
FIVE-YEAR AVERAGE							
16-20	156,100	272	0	12	0	260-	0

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 369.00 SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1995	55,838	33,744	60	9,329	17	24,415-	44-
1996	60,396	33,243	55	9,482	16	23,761-	39-
1997	65,683	35,312	54	6,561	10	28,751-	44-
1998	61,744	43,683	71	9,058	15	34,625-	56-
1999	64,579	47,414	73	9,374	15	38,040-	59-
2000	59,718	39,648	66	5,671	9	33,977-	57-
2001	51,043	41,324	81	6,612	13	34,712-	68-
2002	77,403	67,521	87	5,122	7	62,399-	81-
2003	53,529	42,915	80	3,506	7	39,409-	74-
2004	63,696	59,481	93	2,297	4	57,184-	90-
2005	59,120	63,759	108	1,933	3	61,826-	105-
2006	81,750	61,741	76	5,187	6	56,554-	69-
2007	74,624	60,300	81	4,263	6	56,037-	75-
2008	86,097	110,935	129	1,098	1	109,837-	128-
2009	116,887	155,077	133	1,489	1	153,588-	131-
2010	111,159	185,063	166	922	1	184,141-	166-
2011	103,574	129,460	125	201	0	129,259-	125-
2012	99,190	48,200	49	620	1	47,580-	48-
2013	191,139	14,564	8	800	0	13,763-	7-
2014	181,513	35,732	20	1,040	1	34,692-	19-
2015	68,598	36,692	53	1,260	2	35,431-	52-
2016	253,675	13,597	5	138	0	13,459-	5-
2017	69,261	48,480	70	1,066	2	47,413-	68-
2018	200,440	26,675	13	79	0	26,596-	13-
2019	351,586	153,879	44	461	0	153,418-	44-
2020	309,059	143,271	46	877	0	142,394-	46-
TOTAL	2,971,302	1,731,710	58	88,448	3	1,643,262-	55-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
95-97	60,639	34,100	56	8,457	14	25,642-	42-
96-98	62,608	37,413	60	8,367	13	29,046-	46-
97-99	64,002	42,136	66	8,331	13	33,805-	53-
98-00	62,014	43,582	70	8,034	13	35,547-	57-
99-01	58,447	42,795	73	7,219	12	35,576-	61-
00-02	62,721	49,498	79	5,802	9	43,696-	70-
01-03	60,658	50,587	83	5,080	8	45,507-	75-
02-04	64,876	56,639	87	3,642	6	52,997-	82-
03-05	58,782	55,385	94	2,579	4	52,806-	90-
04-06	68,189	61,660	90	3,139	5	58,521-	86-
05-07	71,831	61,933	86	3,794	5	58,139-	81-
06-08	80,824	77,659	96	3,516	4	74,143-	92-

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 369.00 SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
07-09	92,536	108,771	118	2,283	2	106,487-	115-
08-10	104,714	150,358	144	1,170	1	149,189-	142-
09-11	110,540	156,533	142	871	1	155,663-	141-
10-12	104,641	120,908	116	581	1	120,327-	115-
11-13	131,301	64,075	49	541	0	63,534-	48-
12-14	157,281	32,832	21	820	1	32,012-	20-
13-15	147,083	28,996	20	1,034	1	27,962-	19-
14-16	167,928	28,674	17	813	0	27,861-	17-
15-17	130,511	32,923	25	822	1	32,101-	25-
16-18	174,459	29,584	17	428	0	29,156-	17-
17-19	207,096	76,345	37	535	0	75,809-	37-
18-20	287,029	107,942	38	472	0	107,469-	37-
FIVE-YEAR AVERAGE							
16-20	236,804	77,180	33	524	0	76,656-	32-

UNITIL ENERGY SYSTEMS, INC.

ACCOUNTS 370.00 AND 370.01 METERS AND METER INSTALLATIONS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1995	30,569		0	3,669	12	3,669	12
1996	22,292		0	2,220	10	2,220	10
1997	503		0		0		0
1998	6,118		0		0		0
1999							
2000	2,506		0		0		0
2001	989		0		0		0
2002	189,857	67,521	36		0	67,521-	36-
2003	122,849		0		0		0
2004	19,803		0		0		0
2005	237,293		0		0		0
2006	78,098		0		0		0
2007	465		0		0		0
2008	6,793,533	961,518	14	50,349	1	911,169-	13-
2009	159	6,399			0	6,399-	
2010	16,466	1,246	8		0	1,246-	8-
2011	134,112	513	0	4	0	510-	0
2012	50,809	3,173	6		0	3,173-	6-
2013	254,705	3,624	1	6	0	3,617-	1-
2014	367,090	576	0	25	0	551-	0
2015	295,827		0		0		0
2016	78,332		0		0		0
2017	441,642	243	0		0	243-	0
2018							
2019	718,255	9,813	1		0	9,813-	1-
2020		10,008				10,008-	
TOTAL	9,862,272	1,064,634	11	56,273	1	1,008,360-	10-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
95-97	17,788		0	1,963	11	1,963	11
96-98	9,638		0	740	8	740	8
97-99	2,207		0		0		0
98-00	2,875		0		0		0
99-01	1,165		0		0		0
00-02	64,451	22,507	35		0	22,507-	35-
01-03	104,565	22,507	22		0	22,507-	22-
02-04	110,836	22,507	20		0	22,507-	20-
03-05	126,648		0		0		0
04-06	111,731		0		0		0
05-07	105,285		0		0		0
06-08	2,290,699	320,506	14	16,783	1	303,723-	13-

UNITIL ENERGY SYSTEMS, INC.

ACCOUNTS 370.00 AND 370.01 METERS AND METER INSTALLATIONS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
07-09	2,264,719	322,639	14	16,783	1	305,856-	14-
08-10	2,270,053	323,054	14	16,783	1	306,271-	13-
09-11	50,246	2,719	5	1	0	2,718-	5-
10-12	67,129	1,644	2	1	0	1,643-	2-
11-13	146,542	2,437	2	3	0	2,433-	2-
12-14	224,201	2,458	1	10	0	2,447-	1-
13-15	305,874	1,400	0	10	0	1,389-	0
14-16	247,083	192	0	8	0	184-	0
15-17	271,934	81	0		0	81-	0
16-18	173,325	81	0		0	81-	0
17-19	386,632	3,352	1		0	3,352-	1-
18-20	239,418	6,607	3		0	6,607-	3-
FIVE-YEAR AVERAGE							
16-20	247,646	4,013	2		0	4,013-	2-

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1995	41,358	23,207	56	8,054	19	15,153-	37-
1996	47,707	26,130	55	7,566	16	18,564-	39-
1997	40,520	20,563	51	4,270	11	16,293-	40-
1998	37,116	27,865	75	5,479	15	22,386-	60-
1999	28,156	20,587	73	3,822	14	16,765-	60-
2000	37,157	24,091	65	3,362	9	20,729-	56-
2001	25,576	21,010	82	4,662	18	16,348-	64-
2002	44,555	38,345	86	2,988	7	35,357-	79-
2003	49,025	40,657	83	3,051	6	37,606-	77-
2004	47,611	33,121	70	1,813	4	31,308-	66-
2005	41,240	46,947	114	1,527	4	45,420-	110-
2006	55,401	38,132	69	2,992	5	35,140-	63-
2007	48,583	39,091	80	2,845	6	36,246-	75-
2008	121,707	26,608	22	4,239	3	22,369-	18-
2009	38,733	15,842	41	6,498	17	9,344-	24-
2010	48,887	22,926	47	7,023	14	15,903-	33-
2011	116,833	39,517	34	9,537	8	29,980-	26-
2012	130,996	56,565	43	15,463	12	41,102-	31-
2013	113,528	14,929	13	13,905	12	1,024-	1-
2014	108,710	15,146	14	8,302	8	6,844-	6-
2015	94,402	15,515	16	8,398	9	7,117-	8-
2016	129,864	14,109	11	10,368	8	3,740-	3-
2017	93,396	9,109	10	7,788	8	1,321-	1-
2018	141,975	17,061	12	17,305	12	244	0
2019	135,485	18,161	13	10,470	8	7,691-	6-
2020	174,274	55,532	32	22,678	13	32,854-	19-
TOTAL	1,992,795	720,765	36	194,405	10	526,360-	26-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
95-97	43,195	23,300	54	6,630	15	16,670-	39-
96-98	41,781	24,853	59	5,772	14	19,081-	46-
97-99	35,264	23,005	65	4,524	13	18,481-	52-
98-00	34,143	24,181	71	4,221	12	19,960-	58-
99-01	30,296	21,896	72	3,949	13	17,947-	59-
00-02	35,763	27,815	78	3,671	10	24,145-	68-
01-03	39,719	33,337	84	3,567	9	29,770-	75-
02-04	47,064	37,374	79	2,617	6	34,757-	74-
03-05	45,959	40,242	88	2,130	5	38,111-	83-
04-06	48,084	39,400	82	2,111	4	37,289-	78-
05-07	48,408	41,390	86	2,455	5	38,935-	80-
06-08	75,230	34,610	46	3,359	4	31,252-	42-

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
07-09	69,674	27,180	39	4,527	6	22,653-	33-
08-10	69,776	21,792	31	5,920	8	15,872-	23-
09-11	68,151	26,095	38	7,686	11	18,409-	27-
10-12	98,905	39,669	40	10,674	11	28,995-	29-
11-13	120,452	37,004	31	12,968	11	24,035-	20-
12-14	117,744	28,880	25	12,557	11	16,323-	14-
13-15	105,546	15,197	14	10,202	10	4,995-	5-
14-16	110,992	14,923	13	9,023	8	5,900-	5-
15-17	105,887	12,911	12	8,852	8	4,059-	4-
16-18	121,745	13,426	11	11,821	10	1,606-	1-
17-19	123,619	14,777	12	11,854	10	2,923-	2-
18-20	150,578	30,251	20	16,818	11	13,434-	9-
FIVE-YEAR AVERAGE							
16-20	134,999	22,794	17	13,722	10	9,072-	7-

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1995	187,906	112,881	60	31,825	17	81,056-	43-
1996	34,120	17,421	51	6,149	18	11,272-	33-
1997	57,766	28,682	50	6,204	11	22,478-	39-
1998	83,192	45,941	55	11,936	14	34,005-	41-
1999	87,020	63,893	73	12,635	15	51,258-	59-
2000	113,890	74,986	66	10,634	9	64,352-	57-
2001	74,312	59,553	80	6,911	9	52,642-	71-
2002	53,339	46,526	87	3,530	7	42,996-	81-
2003	93,478	72,966	78	6,335	7	66,631-	71-
2004	85,600	81,060	95	2,770	3	78,290-	91-
2005	69,649	73,333	105	2,149	3	71,184-	102-
2006	144,281	112,565	78	9,661	7	102,904-	71-
2007	108,197	87,334	81	6,220	6	81,114-	75-
2008	171,617	35,541	21	19,006	11	16,535-	10-
2009	112,312	45,643	41	22,613	20	23,030-	21-
2010	98,727	44,482	45	16,150	16	28,332-	29-
2011	89,191	42,804	48	8,520	10	34,283-	38-
2012	81,758	10,172	12	4,396	5	5,776-	7-
2013	100,910	10,792	11	19,855	20	9,063	9
2014	85,091	13,448	16	14,886	17	1,437	2
2015	61,274	6,361	10	11,377	19	5,016	8
2016	137,473	16,746	12	24,549	18	7,803	6
2017	75,996	14,914	20	11,274	15	3,639-	5-
2018	86,645	23,992	28	18,459	21	5,532-	6-
2019	52,176	14,930	29	9,423	18	5,507-	11-
2020	77,881	26,496	34	8,295	11	18,202-	23-
TOTAL	2,423,803	1,183,461	49	305,763	13	877,699-	36-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
95-97	93,264	52,995	57	14,726	16	38,269-	41-
96-98	58,359	30,681	53	8,096	14	22,585-	39-
97-99	75,993	46,172	61	10,258	13	35,914-	47-
98-00	94,701	61,607	65	11,735	12	49,872-	53-
99-01	91,741	66,144	72	10,060	11	56,084-	61-
00-02	80,514	60,355	75	7,025	9	53,330-	66-
01-03	73,710	59,682	81	5,592	8	54,090-	73-
02-04	77,472	66,851	86	4,212	5	62,639-	81-
03-05	82,909	75,786	91	3,751	5	72,035-	87-
04-06	99,843	88,986	89	4,860	5	84,126-	84-
05-07	107,376	91,077	85	6,010	6	85,067-	79-
06-08	141,365	78,480	56	11,629	8	66,851-	47-

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
07-09	130,709	56,173	43	15,946	12	40,226-	31-
08-10	127,552	41,889	33	19,256	15	22,632-	18-
09-11	100,077	44,310	44	15,761	16	28,548-	29-
10-12	89,892	32,486	36	9,689	11	22,797-	25-
11-13	90,620	21,256	23	10,924	12	10,332-	11-
12-14	89,253	11,471	13	13,046	15	1,575	2
13-15	82,425	10,200	12	15,373	19	5,172	6
14-16	94,613	12,185	13	16,937	18	4,752	5
15-17	91,581	12,674	14	15,733	17	3,060	3
16-18	100,038	18,550	19	18,094	18	456-	0
17-19	71,606	17,945	25	13,052	18	4,893-	7-
18-20	72,234	21,806	30	12,059	17	9,747-	13-
FIVE-YEAR AVERAGE							
16-20	86,034	19,416	23	14,400	17	5,016-	6-

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1995	17,354		0		0		0
1996	44,395		0		0		0
1997							
1998	459		0		0		0
1999	15,762		0		0		0
2000							
2001	18,090		0		0		0
2002	3,159		0		0		0
2003	1,950		0		0		0
2004	3,620		0		0		0
2005							
2006	8		0		0		0
2007	4,990		0		0		0
2008	2,973		0		0		0
2009	112,760		0		0		0
2010							
2011							
2012	17,101	4,870	28		0	4,870-	28-
2013	3,490		0		0		0
2014	227,379		0		0		0
2015							
2016	3,908		0		0		0
2017							
2018							
2019							
2020							
TOTAL	477,398	4,870	1		0	4,870-	1-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
95-97	20,583		0		0		0
96-98	14,951		0		0		0
97-99	5,407		0		0		0
98-00	5,407		0		0		0
99-01	11,284		0		0		0
00-02	7,083		0		0		0
01-03	7,733		0		0		0
02-04	2,910		0		0		0
03-05	1,857		0		0		0
04-06	1,209		0		0		0
05-07	1,666		0		0		0
06-08	2,657		0		0		0

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
THREE-YEAR MOVING AVERAGES							
07-09	40,241		0		0		0
08-10	38,578		0		0		0
09-11	37,587		0		0		0
10-12	5,700	1,623	28		0	1,623-	28-
11-13	6,864	1,623	24		0	1,623-	24-
12-14	82,657	1,623	2		0	1,623-	2-
13-15	76,956		0		0		0
14-16	77,096		0		0		0
15-17	1,303		0		0		0
16-18	1,303		0		0		0
17-19							
18-20							
FIVE-YEAR AVERAGE							
16-20	782		0		0		0

PART IX. DETAILED DEPRECIATION CALCULATIONS

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 343.00 PRIME MOVERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 10-S3						
NET SALVAGE PERCENT.. 0						
2007	10,383.44	9,366	7,585	2,798	0.98	2,798
2011	45,988.70	35,963	29,124	16,865	2.18	7,736
2015	203.08	108	87	116	4.67	25
	56,575.22	45,437	36,796	19,779		10,559

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.9   18.66

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R4						
NET SALVAGE PERCENT.. -30						
1934	4,799.12	6,239	6,239			
1938	1,260.31	1,627	1,544	94	0.37	94
1939	162.38	209	198	13	0.52	13
1950	53.04	65	62	7	3.02	2
1951	768.94	940	892	108	3.27	33
1952	9,483.59	11,535	10,945	1,384	3.54	391
1954	790.29	951	902	125	4.08	31
1957	2,308.40	2,732	2,592	409	4.93	83
1960	398.00	462	438	79	5.88	13
1962	733.85	840	797	157	6.59	24
1963	471.00	535	508	104	6.97	15
1965	459.00	512	486	111	7.82	14
1966	15,858.00	17,508	16,612	4,003	8.29	483
1967	1,399.00	1,528	1,450	369	8.78	42
1968	3,806.00	4,110	3,900	1,048	9.31	113
1969	86.00	92	87	25	9.86	3
1970	2,361.05	2,487	2,360	709	10.44	68
1971	9,422.48	9,788	9,287	2,962	11.05	268
1978	1,717.00	1,591	1,510	722	15.80	46
1979	10,789.98	9,811	9,309	4,718	16.53	285
1980	22,490.77	20,052	19,026	10,212	17.28	591
1981	5,975.00	5,220	4,953	2,814	18.04	156
1982	4,607.07	3,941	3,739	2,250	18.81	120
1997	26,232.65	14,342	13,608	20,494	31.87	643
2002	36,867.13	15,973	15,156	32,771	36.67	894
2003	4,473.00	1,835	1,741	4,074	37.64	108
2016	917,119.98	97,336	92,355	1,099,901	50.51	21,776
2017	1,088,723.41	90,072	85,463	1,329,877	51.50	25,823
	2,173,616.44	322,333	306,159	2,519,542		52,132

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 48.3   2.40

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 362.00 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

SURVIVOR CURVE.. IOWA 49-R1.5
NET SALVAGE PERCENT.. -40

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1934	11,574.16	14,970	13,210	2,994	3.73	803
1935	2,594.72	3,339	2,946	687	3.96	173
1936	194.27	249	220	52	4.18	12
1938	15,701.37	19,905	17,565	4,417	4.63	954
1939	3,100.85	3,910	3,450	891	4.87	183
1940	4,028.52	5,052	4,458	1,182	5.11	231
1941	13,490.16	16,824	14,846	4,040	5.35	755
1942	35.80	44	39	11	5.61	2
1944	24.21	30	26	8	6.13	1
1945	332.12	404	356	109	6.40	17
1947	150.88	181	160	51	6.95	7
1948	1,131.03	1,349	1,190	393	7.24	54
1949	38,981.20	46,187	40,757	13,817	7.53	1,835
1950	34,010.98	40,016	35,311	12,304	7.82	1,573
1951	77,164.44	90,150	79,550	28,480	8.11	3,512
1952	32,024.56	37,130	32,764	12,070	8.42	1,433
1953	16,580.70	19,082	16,838	6,375	8.72	731
1954	39,059.88	44,606	39,361	15,323	9.03	1,697
1955	7,092.69	8,035	7,090	2,840	9.35	304
1956	1,029.28	1,157	1,021	420	9.67	43
1957	11,083.30	12,350	10,898	4,619	10.00	462
1958	6,445.23	7,119	6,282	2,741	10.34	265
1959	50,894.08	55,722	49,170	22,082	10.68	2,068
1960	19,643.56	21,311	18,805	8,696	11.03	788
1961	7,828.71	8,412	7,423	3,537	11.39	311
1962	54,140.53	57,606	50,833	24,964	11.76	2,123
1963	9,938.57	10,467	9,236	4,678	12.14	385
1964	72,614.63	75,665	66,769	34,891	12.53	2,785
1965	81,350.10	83,861	74,001	39,889	12.92	3,087
1966	42,701.76	43,519	38,402	21,380	13.33	1,604
1967	119,319.88	120,173	106,044	61,004	13.75	4,437
1968	181,048.63	180,170	158,986	94,482	14.17	6,668
1969	40,270.98	39,569	34,917	21,462	14.61	1,469
1970	159,438.50	154,609	136,431	86,783	15.06	5,762
1971	147,932.91	141,509	124,871	82,235	15.52	5,299
1972	113,913.38	107,436	94,804	64,675	15.99	4,045
1973	78,879.42	73,313	64,693	45,738	16.47	2,777
1974	165,337.17	151,355	133,559	97,913	16.96	5,773
1975	351,013.50	316,312	279,121	212,298	17.46	12,159
1976	50,659.07	44,913	39,632	31,291	17.97	1,741
1977	101,212.35	88,199	77,829	63,868	18.50	3,452
1978	114,317.74	97,888	86,379	73,666	19.03	3,871
1979	88,253.55	74,208	65,483	58,072	19.57	2,967

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 362.00 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

SURVIVOR CURVE.. IOWA 49-R1.5
NET SALVAGE PERCENT.. -40

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1980	191,973.73	158,350	139,732	129,031	20.13	6,410
1981	181,650.48	146,931	129,655	124,656	20.69	6,025
1982	119,573.00	94,736	83,597	83,805	21.27	3,940
1983	226,468.26	175,674	155,019	162,037	21.85	7,416
1984	165,355.65	125,481	110,727	120,771	22.44	5,382
1985	107,115.52	79,418	70,080	79,882	23.05	3,466
1986	16,385.16	11,863	10,468	12,471	23.66	527
1987	75,319.06	53,197	46,942	58,505	24.28	2,410
1988	74,733.70	51,438	45,390	59,237	24.91	2,378
1989	88,796.55	59,494	52,499	71,816	25.55	2,811
1990	392,094.06	255,423	225,391	323,541	26.20	12,349
1991	400,501.83	253,460	223,659	337,044	26.85	12,553
1992	285,462.76	175,194	154,595	245,053	27.52	8,905
1993	210,259.06	125,013	110,315	184,048	28.19	6,529
1994	276,060.42	158,776	140,108	246,377	28.87	8,534
1995	199,938.97	111,109	98,045	181,870	29.55	6,155
1996	299,258.84	160,316	141,467	277,495	30.25	9,173
1997	681,434.91	351,428	310,109	643,900	30.95	20,805
1998	212,238.91	105,150	92,787	204,347	31.66	6,454
1999	710,240.08	337,468	297,790	696,546	32.37	21,518
2000	207,246.57	94,207	83,131	207,014	33.09	6,256
2001	265,310.81	115,071	101,541	269,894	33.82	7,980
2002	511,115.12	211,019	186,208	529,353	34.55	15,321
2003	470,665.64	184,369	162,692	496,240	35.29	14,062
2004	828,542.27	307,030	270,931	889,028	36.03	24,675
2005	533,702.57	186,340	164,431	582,753	36.78	15,844
2006	1,235,662.37	404,941	357,330	1,372,597	37.53	36,573
2007	746,052.40	228,291	201,449	843,024	38.29	22,017
2008	2,207,329.26	627,508	553,728	2,536,533	39.05	64,956
2009	1,837,059.53	481,842	425,189	2,146,694	39.82	53,910
2010	510,137.36	122,577	108,165	606,027	40.59	14,930
2011	1,571,665.45	342,614	302,331	1,898,001	41.37	45,879
2012	651,534.72	127,327	112,356	799,793	42.16	18,970
2013	2,302,037.43	398,570	351,708	2,871,144	42.94	66,864
2014	863,431.18	129,765	114,508	1,094,296	43.74	25,018
2015	321,081.23	41,005	36,184	413,330	44.53	9,282
2016	11,484,358.74	1,204,250	1,062,659	15,015,443	45.33	331,247
2017	10,265,078.79	838,842	740,214	13,630,896	46.14	295,425

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 362.00 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 49-R1.5						
NET SALVAGE PERCENT.. -40						
2018	852,291.32	49,924	44,054	1,149,154	46.95	24,476
2019	712,294.39	25,030	22,087	975,125	47.77	20,413
2020	4,754,134.26	55,709	49,159	6,606,629	48.59	135,967
	50,412,131.73	11,484,456	10,134,156	60,442,828		1,492,423

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 40.5 2.96

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

SURVIVOR CURVE.. IOWA 50-R1.5
NET SALVAGE PERCENT.. -80

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1934	8,260.79	13,617	13,563	1,306	4.21	310
1935	244.88	402	400	41	4.43	9
1936	4,406.39	7,192	7,163	769	4.66	165
1937	13,060.44	21,210	21,125	2,384	4.89	488
1938	1,495.03	2,415	2,405	286	5.13	56
1939	524.90	843	840	105	5.37	20
1940	2,775.81	4,435	4,417	579	5.62	103
1941	1,239.76	1,969	1,961	271	5.88	46
1942	2,328.40	3,676	3,661	530	6.14	86
1943	1,477.40	2,318	2,309	350	6.41	55
1944	2,423.40	3,779	3,764	598	6.68	90
1945	1,216.64	1,885	1,877	313	6.96	45
1946	1,996.90	3,074	3,062	532	7.24	73
1947	3,010.42	4,604	4,586	833	7.52	111
1948	8,882.45	13,491	13,437	2,551	7.81	327
1949	13,564.51	20,456	20,374	4,042	8.11	498
1950	15,130.50	22,654	22,564	4,671	8.41	555
1951	14,871.64	22,106	22,018	4,751	8.71	545
1952	15,866.04	23,407	23,314	5,245	9.02	581
1953	13,979.41	20,468	20,386	4,777	9.33	512
1954	32,965.33	47,885	47,694	11,644	9.65	1,207
1955	25,835.01	37,230	37,082	9,421	9.97	945
1956	32,363.86	46,254	46,070	12,185	10.30	1,183
1957	37,038.64	52,482	52,273	14,397	10.64	1,353
1958	48,237.17	67,742	67,472	19,355	10.99	1,761
1959	39,984.42	55,649	55,427	16,545	11.34	1,459
1960	46,545.45	64,177	63,921	19,861	11.70	1,698
1961	57,270.16	78,201	77,889	25,197	12.07	2,088
1962	45,270.91	61,197	60,953	20,535	12.45	1,649
1963	49,085.24	65,664	65,402	22,951	12.84	1,787
1964	70,682.89	93,539	93,166	34,063	13.24	2,573
1965	88,371.32	115,643	115,182	43,886	13.65	3,215
1966	121,747.09	157,477	156,849	62,296	14.07	4,428
1967	107,529.75	137,462	136,914	56,640	14.49	3,909
1968	102,861.54	129,865	129,347	55,804	14.93	3,738
1969	92,108.25	114,796	114,338	51,457	15.38	3,346
1970	149,982.15	184,442	183,706	86,262	15.84	5,446
1971	162,831.69	197,489	196,701	96,396	16.31	5,910
1972	252,115.93	301,420	300,218	153,591	16.79	9,148
1973	201,045.11	236,815	235,870	126,011	17.28	7,292
1974	383,221.21	444,506	442,733	247,065	17.78	13,896
1975	282,719.19	322,741	321,454	187,441	18.29	10,248
1976	271,475.30	304,823	303,607	185,049	18.81	9,838

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R1.5						
NET SALVAGE PERCENT.. -80						
1977	227,706.84	251,252	250,250	159,622	19.35	8,249
1978	268,778.29	291,345	290,183	193,618	19.89	9,734
1979	341,630.68	363,550	362,100	252,835	20.44	12,370
1980	302,035.98	315,326	314,068	229,597	21.00	10,933
1981	346,172.11	354,176	352,763	270,347	21.58	12,528
1982	373,493.60	374,330	372,837	299,451	22.16	13,513
1983	620,253.72	608,469	606,042	510,415	22.75	22,436
1984	529,680.62	508,176	506,149	447,276	23.35	19,155
1985	542,809.98	508,852	506,823	470,235	23.96	19,626
1986	616,438.74	564,115	561,865	547,725	24.58	22,283
1987	687,947.59	613,952	611,503	626,803	25.21	24,863
1988	641,835.47	558,243	556,017	599,287	25.84	23,192
1989	571,831.73	483,976	482,046	547,251	26.49	20,659
1990	583,384.39	480,102	478,187	571,905	27.14	21,072
1991	530,141.92	423,689	421,999	532,256	27.80	19,146
1992	532,344.09	412,609	410,963	547,256	28.47	19,222
1993	691,586.15	519,354	517,283	727,572	29.14	24,968
1994	574,456.90	417,125	415,461	618,561	29.83	20,736
1995	619,501.46	434,444	432,711	682,392	30.52	22,359
1996	732,526.56	495,247	493,272	825,276	31.22	26,434
1997	1,072,951.87	698,363	695,578	1,235,735	31.92	38,714
1998	884,959.83	553,383	551,176	1,041,752	32.63	31,926
1999	1,220,963.58	731,846	728,927	1,468,807	33.35	44,042
2000	1,105,622.68	634,052	631,523	1,358,598	34.07	39,877
2001	1,014,139.74	554,937	552,724	1,272,728	34.80	36,573
2002	1,332,155.03	693,946	691,178	1,706,701	35.53	48,035
2003	2,324,316.08	1,148,863	1,144,281	3,039,488	36.27	83,802
2004	1,626,432.30	759,999	756,968	2,170,610	37.02	58,633
2005	1,474,946.50	649,389	646,799	2,008,105	37.77	53,167
2006	2,407,560.15	994,996	991,028	3,342,580	38.52	86,775
2007	2,338,288.08	902,392	898,793	3,310,126	39.28	84,270
2008	2,972,091.62	1,064,603	1,060,357	4,289,408	40.05	107,101
2009	2,421,003.56	800,093	796,902	3,560,904	40.82	87,234
2010	2,438,698.89	738,340	735,395	3,654,263	41.59	87,864
2011	1,963,513.13	539,338	537,187	2,997,137	42.37	70,737
2012	3,148,628.26	776,452	773,355	4,894,176	43.15	113,422
2013	3,532,010.10	770,543	767,470	5,590,148	43.94	127,222
2014	3,131,840.63	594,173	591,803	5,045,510	44.73	112,799
2015	3,133,170.25	504,190	502,179	5,137,527	45.53	112,838
2016	2,969,262.74	392,299	390,734	4,953,939	46.33	106,927
2017	4,606,886.64	474,325	472,433	7,819,963	47.14	165,888

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R1.5						
NET SALVAGE PERCENT.. -80						
2018	4,696,707.87	346,617	345,235	8,108,839	47.95	169,110
2019	4,273,370.61	189,225	188,471	7,503,596	48.77	153,857
2020	5,888,740.32	86,918	86,571	10,513,162	49.59	212,002
	75,140,860.60	28,089,114	27,977,083	107,276,466		2,709,085

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 39.6   3.61

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

SURVIVOR CURVE.. IOWA 45-R0.5
NET SALVAGE PERCENT.. -65

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1934	37,969.43	60,269	62,615	35	1.71	20
1935	7,493.72	11,766	12,224	141	2.18	65
1936	2,087.42	3,241	3,367	77	2.65	29
1937	18,036.82	27,697	28,775	986	3.12	316
1938	3,328.96	5,057	5,254	239	3.57	67
1939	4,377.72	6,578	6,834	389	4.02	97
1940	4,073.90	6,056	6,292	430	4.46	96
1941	4,225.83	6,215	6,457	516	4.89	106
1942	2,660.08	3,871	4,022	367	5.31	69
1943	2,605.14	3,751	3,897	401	5.73	70
1944	969.08	1,381	1,435	164	6.14	27
1945	2,370.45	3,342	3,472	439	6.55	67
1946	11,207.99	15,633	16,242	2,251	6.96	323
1947	16,877.33	23,293	24,200	3,648	7.36	496
1948	21,299.02	29,083	30,215	4,928	7.76	635
1949	32,191.28	43,496	45,189	7,927	8.15	973
1950	22,617.81	30,229	31,406	5,913	8.55	692
1951	22,216.41	29,366	30,509	6,148	8.95	687
1952	24,008.95	31,392	32,614	7,001	9.34	750
1953	44,148.16	57,078	59,300	13,544	9.74	1,391
1954	38,842.33	49,648	51,581	12,509	10.14	1,234
1955	42,596.60	53,838	55,934	14,350	10.53	1,363
1956	31,259.66	39,051	40,571	11,007	10.93	1,007
1957	45,131.17	55,701	57,869	16,597	11.34	1,464
1958	39,418.86	48,073	49,944	15,097	11.74	1,286
1959	38,434.63	46,295	48,097	15,320	12.15	1,261
1960	50,404.16	59,954	62,288	20,879	12.56	1,662
1961	58,195.71	68,347	71,008	25,015	12.97	1,929
1962	55,566.32	64,403	66,910	24,774	13.39	1,850
1963	41,959.63	47,986	49,854	19,379	13.81	1,403
1964	79,163.58	89,315	92,792	37,828	14.23	2,658
1965	96,628.61	107,496	111,681	47,756	14.66	3,258
1966	138,663.94	152,074	157,994	70,802	15.09	4,692
1967	123,400.85	133,343	138,534	65,077	15.53	4,190
1968	158,818.24	169,051	175,632	86,418	15.97	5,411
1969	111,468.98	116,812	121,359	62,565	16.42	3,810
1970	321,385.59	331,487	344,391	185,895	16.87	11,019
1971	289,397.25	293,718	305,152	172,353	17.32	9,951
1972	315,253.64	314,645	326,894	193,275	17.78	10,870
1973	209,588.95	205,570	213,573	132,249	18.25	7,247
1974	453,165.13	436,670	453,669	294,053	18.72	15,708
1975	287,198.89	271,798	282,379	191,499	19.19	9,979
1976	197,727.49	183,643	190,792	135,458	19.67	6,887

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R0.5						
NET SALVAGE PERCENT.. -65						
1977	198,275.27	180,661	187,694	139,460	20.15	6,921
1978	253,325.88	226,269	235,077	182,911	20.64	8,862
1979	270,876.03	236,979	246,204	200,741	21.14	9,496
1980	211,493.85	181,151	188,203	160,762	21.64	7,429
1981	284,455.15	238,430	247,712	221,639	22.14	10,011
1982	297,506.68	243,695	253,182	237,704	22.66	10,490
1983	363,031.37	290,582	301,894	297,108	23.17	12,823
1984	366,088.96	286,052	297,188	306,859	23.69	12,953
1985	558,556.31	425,585	442,153	479,465	24.22	19,796
1986	633,497.00	470,372	488,683	556,587	24.75	22,488
1987	708,174.03	512,054	531,988	636,499	25.28	25,178
1988	784,072.88	551,409	572,875	720,845	25.82	27,918
1989	835,231.69	570,547	592,758	785,374	26.37	29,783
1990	746,565.35	494,926	514,193	717,640	26.92	26,658
1991	602,731.92	387,420	402,502	592,006	27.47	21,551
1992	757,853.30	471,560	489,917	760,541	28.03	27,133
1993	991,254.28	596,443	619,662	1,015,908	28.59	35,534
1994	724,611.89	420,855	437,238	758,372	29.16	26,007
1995	814,074.59	455,796	473,540	869,683	29.73	29,253
1996	1,037,738.13	559,347	581,122	1,131,146	30.30	37,332
1997	1,614,988.50	836,726	869,299	1,795,432	30.87	58,161
1998	1,326,622.20	659,108	684,766	1,504,161	31.45	47,827
1999	1,293,442.33	614,644	638,571	1,495,609	32.04	46,679
2000	1,479,850.38	671,751	697,902	1,743,851	32.62	53,460
2001	1,286,873.50	556,315	577,972	1,545,369	33.21	46,533
2002	1,890,482.31	776,362	806,585	2,312,711	33.80	68,423
2003	2,850,588.67	1,108,984	1,152,155	3,551,316	34.39	103,266
2004	2,218,793.71	815,197	846,932	2,814,078	34.98	80,448
2005	2,135,777.26	737,686	766,403	2,757,629	35.58	77,505
2006	3,378,772.90	1,093,922	1,136,507	4,438,468	36.17	122,711
2007	3,311,318.02	999,251	1,038,151	4,425,524	36.77	120,357
2008	5,100,243.53	1,426,916	1,482,464	6,932,938	37.37	185,521
2009	2,991,626.41	771,131	801,150	4,135,034	37.97	108,903
2010	3,080,500.30	726,285	754,559	4,328,266	38.57	112,218
2011	3,880,184.68	828,010	860,243	5,542,062	39.18	141,451
2012	3,163,587.85	605,511	629,083	4,590,837	39.78	115,406
2013	4,822,761.30	815,172	846,906	7,110,650	40.39	176,050
2014	3,679,284.51	539,635	560,642	5,510,177	41.00	134,395
2015	3,788,217.68	470,855	489,185	5,761,374	41.61	138,461
2016	3,393,968.50	345,971	359,439	5,240,609	42.22	124,126
2017	5,696,493.56	451,162	468,725	8,930,489	42.84	208,461

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

SURVIVOR CURVE.. IOWA 45-R0.5
NET SALVAGE PERCENT.. -65

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
2018	4,257,871.40	241,958	251,377	6,774,111	43.45	155,906
2019	4,600,897.14	156,916	163,025	7,428,455	44.07	168,560
2020	6,122,725.95	69,606	72,316	10,030,182	44.69	224,439
	92,313,722.86	27,856,919	28,941,359	123,376,284		3,343,998

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 36.9 3.62

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 366.00 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R2.5						
NET SALVAGE PERCENT.. -25						
1949	4,665.10	4,861	4,488	1,343	9.98	135
1954	324.61	327	302	104	11.66	9
1956	3,290.64	3,262	3,012	1,101	12.42	89
1958	3,044.45	2,966	2,738	1,068	13.23	81
1966	1,155.53	1,033	954	490	17.08	29
1970	206.54	175	162	96	19.34	5
1971	60,844.25	50,792	46,894	29,161	19.93	1,463
1972	27,754.37	22,817	21,066	13,627	20.54	663
1973	2,032.60	1,645	1,519	1,022	21.16	48
1974	53,033.65	42,217	38,977	27,315	21.79	1,254
1975	3,829.03	2,996	2,766	2,020	22.44	90
1976	1,056.53	812	750	571	23.09	25
1977	52,581.96	39,699	36,653	29,074	23.76	1,224
1978	3,451.42	2,558	2,362	1,952	24.43	80
1979	3,082.44	2,241	2,069	1,784	25.11	71
1980	6,285.74	4,477	4,133	3,724	25.81	144
1981	1,446.38	1,009	932	876	26.51	33
1982	7,606.56	5,193	4,794	4,714	27.23	173
1983	3,382.69	2,259	2,086	2,142	27.95	77
1984	31,293.51	20,419	18,852	20,265	28.68	707
1985	54,015.00	34,412	31,771	35,748	29.42	1,215
1986	26,725.86	16,609	15,334	18,073	30.17	599
1987	33,743.55	20,443	18,874	23,305	30.92	754
1988	14,442.13	8,518	7,864	10,189	31.69	322
1989	8,269.55	4,745	4,381	5,956	32.46	183
1990	15,448.75	8,613	7,952	11,359	33.24	342
1991	8,538.81	4,620	4,265	6,409	34.03	188
1992	47,679.52	25,012	23,093	36,506	34.82	1,048
1993	85,908.25	43,617	40,270	67,115	35.63	1,884
1994	14,568.12	7,151	6,602	11,608	36.44	319
1995	81,295.41	38,531	35,574	66,045	37.25	1,773
1996	59,403.23	27,127	25,045	49,209	38.08	1,292
1997	139,193.87	61,158	56,465	117,527	38.91	3,020
1998	32,032.54	13,521	12,483	27,558	39.74	693
1999	54,346.56	21,976	20,290	47,643	40.59	1,174
2000	39,186.96	15,152	13,989	34,995	41.44	844
2001	50,242.89	18,527	17,105	45,699	42.30	1,080
2002	34,303.77	12,035	11,112	31,768	43.16	736
2003	66,006.75	21,961	20,276	62,232	44.03	1,413
2004	79,557.99	25,028	23,107	76,340	44.90	1,700
2005	85,919.63	25,454	23,501	83,899	45.78	1,833
2006	46,671.54	12,961	11,966	46,373	46.67	994
2007	19,027.69	4,931	4,553	19,232	47.56	404

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 366.00 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R2.5						
NET SALVAGE PERCENT.. -25						
2008	2,209.65	532	491	2,271	48.45	47
2009	63,274.13	14,039	12,962	66,131	49.35	1,340
2010	72,713.58	14,754	13,622	77,270	50.26	1,537
2011	7,371.14	1,356	1,252	7,962	51.17	156
2012	40,501.71	6,683	6,170	44,457	52.08	854
2013	84,657.47	12,346	11,399	94,423	53.00	1,782
2014	52,805.50	6,688	6,175	59,832	53.92	1,110
2015	141,563.09	15,188	14,022	162,932	54.85	2,971
2016	31,727.97	2,796	2,581	37,079	55.77	665
2017	73,883.65	5,064	4,676	87,679	56.71	1,546
2018	172,707.30	8,491	7,839	208,045	57.64	3,609
2019	115,011.60	3,403	3,142	140,622	58.58	2,401
2020	362,635.16	3,549	3,277	450,017	59.53	7,559
	2,587,958.32	778,749	718,989	2,515,959		55,787

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 45.1 2.16

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R2.5						
NET SALVAGE PERCENT.. -50						
1950	62.50	81	71	23	7.75	3
1951	1,259.26	1,613	1,417	472	8.02	59
1956	3,724.83	4,625	4,062	1,525	9.47	161
1958	3,674.30	4,495	3,948	1,563	10.14	154
1960	799.60	963	846	353	10.86	33
1962	1,652.27	1,954	1,716	762	11.63	66
1963	327.41	384	337	154	12.04	13
1966	3,536.16	4,015	3,526	1,778	13.37	133
1967	169.94	191	168	87	13.85	6
1970	5,983.87	6,468	5,681	3,295	15.37	214
1971	71,799.00	76,564	67,246	40,452	15.90	2,544
1972	24,788.12	26,055	22,884	14,298	16.46	869
1973	13,724.25	14,216	12,486	8,100	17.02	476
1974	26,597.44	27,129	23,827	16,069	17.60	913
1975	17,039.89	17,102	15,021	10,539	18.20	579
1976	15,399.64	15,204	13,354	9,745	18.80	518
1977	35,282.38	34,237	30,070	22,854	19.42	1,177
1978	32,918.54	31,368	27,550	21,828	20.06	1,088
1979	50,757.27	47,481	41,702	34,434	20.70	1,663
1980	22,077.07	20,255	17,790	15,326	21.36	718
1981	36,338.20	32,674	28,698	25,809	22.03	1,172
1982	44,955.92	39,590	34,772	32,662	22.71	1,438
1983	18,492.86	15,938	13,998	13,741	23.40	587
1984	98,772.99	83,239	73,109	75,050	24.10	3,114
1985	146,716.58	120,801	106,099	113,976	24.81	4,594
1986	256,455.86	206,121	181,036	203,648	25.53	7,977
1987	336,110.73	263,452	231,390	272,776	26.26	10,388
1988	264,636.54	202,086	177,492	219,463	27.00	8,128
1989	210,880.75	156,721	137,648	178,673	27.75	6,439
1990	208,718.51	150,847	132,489	180,589	28.50	6,336
1991	98,980.60	69,458	61,005	87,466	29.27	2,988
1992	156,989.14	106,825	93,824	141,660	30.05	4,714
1993	224,598.82	148,050	130,032	206,866	30.83	6,710
1994	358,098.36	228,336	200,547	336,601	31.62	10,645
1995	463,309.56	285,318	250,594	444,370	32.42	13,707
1996	351,534.09	208,716	183,315	343,986	33.23	10,352
1997	565,041.76	322,845	283,554	564,009	34.05	16,564
1998	508,209.25	279,007	245,051	517,263	34.87	14,834
1999	614,530.60	323,467	284,101	637,695	35.70	17,863
2000	701,875.69	353,366	310,361	742,453	36.54	20,319
2001	799,871.10	384,370	337,592	862,215	37.38	23,066
2002	774,555.33	354,254	311,141	850,692	38.23	22,252
2003	870,835.11	377,860	331,874	974,379	39.09	24,927

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R2.5						
NET SALVAGE PERCENT.. -50						
2004	1,283,625.86	526,511	462,434	1,463,005	39.96	36,612
2005	1,204,414.75	465,458	408,811	1,397,811	40.83	34,235
2006	804,463.09	291,586	256,100	950,595	41.71	22,791
2007	745,456.49	252,307	221,601	896,584	42.59	21,052
2008	774,468.77	243,319	213,707	947,996	43.48	21,803
2009	770,440.56	223,147	195,990	959,671	44.38	21,624
2010	387,017.62	102,596	90,110	490,416	45.28	10,831
2011	213,745.97	51,414	45,157	275,462	46.18	5,965
2012	504,800.55	108,901	95,647	661,554	47.09	14,049
2013	667,312.34	127,213	111,731	889,238	48.01	18,522
2014	695,582.19	115,147	101,133	942,240	48.93	19,257
2015	1,376,060.20	193,281	169,758	1,894,332	49.85	38,001
2016	753,712.10	86,748	76,191	1,054,377	50.78	20,764
2017	1,231,041.01	110,461	97,018	1,749,544	51.71	33,834
2018	1,511,151.37	96,857	85,069	2,181,658	52.65	41,437
2019	1,763,383.80	68,296	59,984	2,585,092	53.58	48,247
2020	734,204.71	9,416	8,270	1,093,037	54.53	20,045
	23,862,963.47	8,120,399	7,132,135	28,662,310		679,570

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 42.2   2.85

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 368.00 LINE TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

SURVIVOR CURVE.. IOWA 40-R1.5
NET SALVAGE PERCENT.. -10

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1934	3,002.19	3,302	3,302			
1935	646.84	712	712			
1936	1,946.71	2,141	2,141			
1937	375.69	413	413			
1939	194.21	214	214			
1940	2,305.74	2,536	2,536			
1941	2,519.29	2,750	2,771			
1942	1,670.31	1,808	1,837			
1943	453.25	487	499			
1944	91.00	97	100			
1945	997.86	1,053	1,098			
1946	1,106.74	1,157	1,217			
1947	5,714.96	5,927	6,286			
1948	5,606.26	5,769	6,167			
1949	3,452.36	3,529	3,798			
1950	3,073.96	3,122	3,381			
1951	10,326.53	10,422	11,359			
1952	8,391.97	8,419	9,231			
1953	19,371.35	19,311	21,308			
1954	7,836.78	7,763	8,620			
1955	19,585.30	19,271	21,544			
1956	28,086.62	27,443	30,895			
1957	26,986.48	26,175	29,685			
1958	19,049.25	18,340	20,954			
1959	38,169.24	36,465	41,836	150	5.26	29
1960	38,559.44	36,541	41,923	492	5.54	89
1961	30,430.39	28,603	32,816	657	5.82	113
1962	35,669.52	33,253	38,151	1,085	6.10	178
1963	31,779.66	29,364	33,689	1,269	6.40	198
1964	18,360.23	16,818	19,295	901	6.69	135
1965	28,306.74	25,688	29,472	1,665	7.00	238
1966	47,453.29	42,659	48,943	3,256	7.31	445
1967	36,308.61	32,331	37,093	2,846	7.62	373
1968	44,318.41	39,061	44,815	3,935	7.95	495
1969	35,152.23	30,663	35,180	3,487	8.28	421
1970	72,231.48	62,332	71,513	7,942	8.62	921
1971	76,735.63	65,480	75,125	9,284	8.97	1,035
1972	128,478.79	108,362	124,324	17,003	9.33	1,822
1973	237,329.03	197,754	226,883	34,179	9.70	3,524
1974	226,396.15	186,279	213,718	35,318	10.08	3,504
1975	41,974.93	34,087	39,108	7,064	10.47	675
1976	121,404.33	97,221	111,542	22,003	10.88	2,022
1977	111,630.09	88,104	101,082	21,711	11.30	1,921

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 368.00 LINE TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R1.5						
NET SALVAGE PERCENT.. -10						
1978	199,271.04	154,918	177,737	41,461	11.73	3,535
1979	152,830.92	116,965	134,194	33,920	12.17	2,787
1980	155,668.65	117,168	134,427	36,809	12.63	2,914
1981	143,894.79	106,446	122,125	36,159	13.10	2,760
1982	158,096.49	114,865	131,784	42,122	13.58	3,102
1983	283,051.29	201,837	231,567	79,789	14.07	5,671
1984	220,103.00	153,863	176,527	65,586	14.58	4,498
1985	432,531.87	296,176	339,802	135,983	15.10	9,005
1986	602,148.43	403,379	462,796	199,567	15.64	12,760
1987	626,257.23	410,058	470,459	218,424	16.19	13,491
1988	633,246.01	404,882	464,521	232,050	16.75	13,854
1989	339,991.16	212,052	243,287	130,703	17.32	7,546
1990	296,453.97	180,170	206,709	119,390	17.90	6,670
1991	144,574.65	85,480	98,071	60,961	18.50	3,295
1992	180,933.31	103,942	119,253	79,774	19.11	4,174
1993	201,913.24	112,607	129,194	92,911	19.72	4,712
1994	245,337.67	132,574	152,102	117,769	20.35	5,787
1995	308,140.54	161,088	184,816	154,139	20.99	7,343
1996	411,553.39	207,680	238,271	214,438	21.65	9,905
1997	473,963.19	230,571	264,534	256,826	22.31	11,512
1998	373,133.84	174,645	200,370	210,077	22.98	9,142
1999	759,064.94	341,086	391,328	443,643	23.66	18,751
2000	627,471.01	270,048	309,826	380,392	24.35	15,622
2001	340,276.27	139,990	160,610	213,694	25.04	8,534
2002	652,092.50	255,539	293,180	424,122	25.75	16,471
2003	758,440.57	282,405	324,003	510,282	26.46	19,285
2004	679,815.48	239,669	274,972	472,825	27.18	17,396
2005	786,162.54	261,379	299,880	564,899	27.91	20,240
2006	1,039,418.48	324,428	372,216	771,144	28.65	26,916
2007	1,869,416.19	545,449	625,793	1,430,565	29.39	48,675
2008	1,169,076.67	316,995	363,688	922,296	30.14	30,600
2009	633,309.49	158,660	182,030	514,610	30.89	16,659
2010	656,520.39	150,753	172,959	549,213	31.65	17,353
2011	12,646.27	2,636	3,024	10,887	32.42	336
2012	1,771,903.54	331,833	380,712	1,568,382	33.19	47,255
2013	1,254,548.65	208,036	238,680	1,141,324	33.97	33,598
2014	916,827.30	132,115	151,575	856,935	34.76	24,653
2015	825,294.19	100,995	115,872	791,952	35.55	22,277
2016	927,438.82	93,347	107,097	913,086	36.34	25,126
2017	1,083,729.18	84,937	97,448	1,094,654	37.15	29,466

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 368.00 LINE TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R1.5						
NET SALVAGE PERCENT.. -10						
2018	1,977,384.88	111,475	127,895	2,047,228	37.95	53,945
2019	1,283,228.03	43,405	49,799	1,361,752	38.77	35,124
2020	1,078,668.33	12,162	13,953	1,172,582	39.59	29,618
	29,259,308.24	9,851,934	11,295,662	20,889,577		720,501

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 29.0 2.46

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 368.01 LINE TRANSFORMER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R1.5						
NET SALVAGE PERCENT.. 0						
1934	31.79	32	32			
1937	4.71	5	5			
1940	4.67	5	5			
1945	27.64	27	28			
1946	23.84	23	24			
1949	549.80	511	550			
1950	14.24	13	14			
1951	239.06	219	239			
1952	47.90	44	48			
1953	1,540.62	1,396	1,541			
1954	304.81	274	305			
1955	80.68	72	81			
1956	1,017.47	904	1,017			
1957	948.07	836	948			
1958	486.63	426	487			
1959	800.87	696	801			
1960	730.37	629	730			
1961	738.80	631	739			
1962	823.10	698	823			
1963	1,825.80	1,534	1,826			
1964	1,728.55	1,439	1,729			
1965	1,591.33	1,313	1,591			
1966	1,710.47	1,398	1,710			
1967	1,823.96	1,476	1,824			
1968	5,046.58	4,044	5,007	40	7.95	5
1969	1,232.23	977	1,210	22	8.28	3
1970	10,280.32	8,065	9,985	295	8.62	34
1971	23,531.91	18,255	22,602	930	8.97	104
1972	16,360.12	12,544	15,531	829	9.33	89
1973	29,816.47	22,586	27,964	1,852	9.70	191
1974	47,318.68	35,394	43,821	3,498	10.08	347
1975	29,155.66	21,524	26,649	2,507	10.47	239
1976	27,868.95	20,289	25,120	2,749	10.88	253
1977	24,388.84	17,499	21,666	2,723	11.30	241
1978	36,875.99	26,062	32,267	4,609	11.73	393
1979	43,282.12	30,114	37,284	5,998	12.17	493
1980	45,953.00	31,443	38,930	7,023	12.63	556
1981	44,068.59	29,636	36,692	7,377	13.10	563
1982	44,991.27	29,717	36,793	8,198	13.58	604
1983	62,412.13	40,459	50,092	12,320	14.07	876
1984	63,170.47	40,145	49,704	13,466	14.58	924
1985	51,487.06	32,051	39,682	11,805	15.10	782
1986	160,678.10	97,853	121,152	39,526	15.64	2,527

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 368.01 LINE TRANSFORMER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R1.5						
NET SALVAGE PERCENT.. 0						
1987	96,776.04	57,606	71,322	25,454	16.19	1,572
1988	64,758.35	37,641	46,603	18,155	16.75	1,084
1989	53,117.83	30,118	37,289	15,829	17.32	914
1990	91,266.63	50,425	62,431	28,836	17.90	1,611
1991	131,200.45	70,520	87,311	43,889	18.50	2,372
1992	51,075.61	26,674	33,025	18,051	19.11	945
1993	145,439.09	73,738	91,295	54,144	19.72	2,746
1994	120,750.95	59,319	73,443	47,308	20.35	2,325
1995	163,649.51	77,774	96,292	67,358	20.99	3,209
1996	103,958.38	47,691	59,046	44,912	21.65	2,074
1997	394,314.60	174,386	215,908	178,407	22.31	7,997
1998	308,409.42	131,228	162,474	145,935	22.98	6,351
1999	309,963.20	126,620	156,768	153,195	23.66	6,475
2000	253,222.75	99,073	122,662	130,561	24.35	5,362
2001	399,517.77	149,420	184,997	214,521	25.04	8,567
2002	761,921.65	271,435	336,064	425,858	25.75	16,538
2003	754,589.20	255,428	316,246	438,343	26.46	16,566
2004	718,636.40	230,323	285,163	433,473	27.18	15,948
2005	986,211.47	298,082	369,056	617,155	27.91	22,112
2006	993,905.45	282,021	349,171	644,734	28.65	22,504
2007	1,524,562.98	404,390	500,676	1,023,887	29.39	34,838
2008	1,199,247.30	295,614	366,000	833,247	30.14	27,646
2009	720,766.36	164,155	203,241	517,525	30.89	16,754
2010	892,683.59	186,348	230,718	661,966	31.65	20,915
2012	2,693,148.44	458,509	567,681	2,125,467	33.19	64,039
2013	738,455.59	111,322	137,828	600,628	33.97	17,681
2014	1,175,746.06	154,023	190,696	985,050	34.76	28,339
2015	1,120,643.51	124,672	154,357	966,287	35.55	27,181
2016	1,104,994.45	101,107	125,181	979,813	36.34	26,962
2017	1,252,751.56	89,259	110,512	1,142,240	37.15	30,747
2018	2,157,785.29	110,586	136,917	2,020,868	37.95	53,251
2019	1,857,925.43	57,131	70,734	1,787,191	38.77	46,097
2020	1,820,633.34	18,661	23,104	1,797,529	39.59	45,404
	25,947,042.32	5,358,557	6,633,459	19,313,583		596,350

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 32.4 2.30

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 369.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. -50						
1934	2,956.43	4,435	4,435			
1935	304.61	457	457			
1936	49.56	74	74			
1937	5.14	8	8			
1938	160.11	240	240			
1939	486.00	729	729			
1940	106.26	159	159			
1941	67.60	101	101			
1942	5.32	8	8			
1943	2,219.44	3,329	3,329			
1944	109.07	164	164			
1945	112.04	168	168			
1946	66.60	100	100			
1947	159.45	238	239			
1948	363.15	538	545			
1949	298.43	440	448			
1950	546.76	800	820			
1951	782.79	1,138	1,174			
1952	243.71	352	366			
1953	822.42	1,178	1,234			
1954	1,337.55	1,902	2,006			
1955	1,519.26	2,145	2,279			
1956	6,107.12	8,558	9,161			
1957	6,861.09	9,540	10,292			
1958	4,394.90	6,063	6,592			
1959	8,802.73	12,049	13,204			
1960	10,695.02	14,523	16,043			
1961	13,158.94	17,725	19,738			
1962	13,092.76	17,494	19,639			
1963	14,326.22	18,980	21,489			
1964	13,947.23	18,327	20,921			
1965	10,962.45	14,281	16,444			
1966	13,973.58	18,047	20,960			
1967	18,125.32	23,198	27,188			
1968	33,320.42	42,246	49,981			
1969	26,990.49	33,897	40,486			
1970	34,531.92	42,940	51,798			
1971	19,954.48	24,551	29,932			
1972	75,869.57	92,352	113,804			
1973	62,793.37	75,588	94,190			
1974	58,755.17	69,889	88,133			
1975	86,962.41	102,170	130,444			
1976	92,895.63	107,747	139,343			

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 369.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

SURVIVOR CURVE.. IOWA 40-R2
NET SALVAGE PERCENT.. -50

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1977	137,767.47	157,623	206,651			
1978	113,681.35	128,233	170,522			
1979	115,511.45	128,348	173,267			
1980	76,188.79	83,341	114,283			
1981	89,846.87	96,664	134,770			
1982	105,891.48	111,980	158,837			
1983	143,122.68	148,669	214,684			
1984	170,077.59	173,352	255,116			
1985	235,976.10	235,740	353,964			
1986	316,715.29	309,866	475,073			
1987	289,602.87	277,259	434,404			
1988	276,629.00	258,821	414,944			
1989	251,167.15	229,441	376,751			
1990	251,161.46	223,691	372,060	4,682	16.25	288
1991	329,389.04	285,704	475,205	18,879	16.87	1,119
1992	280,592.29	236,750	393,781	27,107	17.50	1,549
1993	269,697.32	220,983	367,556	36,990	18.15	2,038
1994	355,170.85	282,228	469,423	63,333	18.81	3,367
1995	363,962.37	280,069	465,832	80,112	19.48	4,113
1996	416,215.19	309,664	515,057	109,266	20.16	5,420
1997	587,038.89	421,347	700,817	179,741	20.86	8,617
1998	461,180.13	318,906	530,429	161,341	21.56	7,483
1999	564,857.68	375,348	624,308	222,979	22.28	10,008
2000	504,756.70	321,593	534,898	222,237	23.01	9,658
2001	543,753.53	331,350	551,127	264,503	23.75	11,137
2002	628,620.42	365,386	607,738	335,193	24.50	13,681
2003	662,686.75	366,300	609,258	384,772	25.26	15,232
2004	691,585.41	362,304	602,612	434,766	26.03	16,702
2005	808,771.10	399,735	664,870	548,287	26.82	20,443
2006	613,447.79	285,023	474,072	446,100	27.61	16,157
2007	731,995.61	318,144	529,162	568,831	28.41	20,022
2008	1,081,359.13	437,545	727,758	894,281	29.21	30,616
2009	834,620.87	312,044	519,015	732,916	30.03	24,406
2010	1,079,696.32	370,066	615,522	1,004,022	30.86	32,535
2011	552,342.73	172,124	286,290	542,224	31.69	17,110
2012	645,592.13	180,604	300,394	667,994	32.54	20,528
2013	1,154,347.28	286,134	475,920	1,255,601	33.39	37,604
2014	980,503.75	211,789	352,264	1,118,492	34.24	32,666
2015	820,540.03	150,467	250,268	980,542	35.11	27,928
2016	1,130,239.55	170,384	283,396	1,411,963	35.98	39,243
2017	1,321,050.14	155,058	257,905	1,723,670	36.87	46,750

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 369.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R2						
NET SALVAGE PERCENT.. -50						
2018	1,253,486.11	105,763	175,913	1,704,316	37.75	45,147
2019	1,442,118.35	73,007	121,431	2,041,747	38.65	52,827
2020	1,320,432.75	22,282	37,061	1,943,588	39.55	49,143
	25,642,632.28	11,479,997	18,333,473	20,130,475		623,537

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 32.3   2.43

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 370.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-R1.5						
NET SALVAGE PERCENT.. 0						
1946	119.91	120	120			
1947	217.71	218	218			
1948	162.90	163	163			
1949	612.43	612	612			
1950	26.39	26	26			
1951	577.54	578	578			
1952	59.96	60	60			
1953	331.57	332	332			
1954	1,592.19	1,592	1,592			
1955	522.83	523	523			
1956	762.72	763	763			
1957	2,364.47	2,364	2,364			
1958	2,387.74	2,388	2,388			
1959	4,673.82	4,674	4,674			
1960	6,132.84	6,133	6,133			
1961	2,403.26	2,403	2,403			
1962	5,921.60	5,922	5,922			
1963	2,993.80	2,994	2,994			
1964	8,510.81	8,511	8,511			
1965	3,572.52	3,573	3,573			
1966	6,424.17	6,424	6,424			
1967	1,915.20	1,915	1,915			
1968	5,317.85	5,318	5,318			
1969	2,638.91	2,639	2,639			
1970	6,267.30	6,267	6,267			
1971	6,329.17	6,329	6,329			
1972	3,963.43	3,963	3,963			
1973	12,927.08	12,927	12,927			
1974	6,915.30	6,915	6,915			
1975	5,192.94	5,193	5,193			
1976	9,213.10	9,213	9,213			
1977	6,270.46	6,270	6,270			
1978	7,234.83	7,235	7,235			
1979	29,890.02	29,890	29,890			
1980	12,174.85	12,175	12,175			
1981	10,296.29	10,178	7,822	2,474	0.23	2,474
1982	9,858.53	9,582	7,364	2,495	0.56	2,495
1983	16,158.44	15,431	11,859	4,299	0.90	4,299
1984	57,214.29	53,724	41,287	15,927	1.22	13,055
1985	73,821.92	68,359	52,534	21,288	1.48	14,384
1986	456,092.43	417,325	320,718	135,374	1.70	79,632
1987	360,223.45	325,462	250,120	110,103	1.93	57,048
1988	591,401.07	527,234	405,184	186,217	2.17	85,814

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 370.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-R1.5						
NET SALVAGE PERCENT.. 0						
1989	360,562.62	316,754	243,428	117,135	2.43	48,204
1990	431,059.09	372,866	286,551	144,508	2.70	53,521
1991	263,391.50	224,146	172,258	91,134	2.98	30,582
1992	656,828.85	549,437	422,247	234,582	3.27	71,738
1993	695,332.81	570,868	438,717	256,616	3.58	71,680
1994	682,078.74	549,414	422,229	259,850	3.89	66,799
1995	367,801.50	290,195	223,017	144,784	4.22	34,309
1996	308,955.55	238,359	183,181	125,775	4.57	27,522
1997	164,216.04	123,655	95,030	69,186	4.94	14,005
1998	228,372.28	167,397	128,646	99,726	5.34	18,675
1999	215,037.19	153,214	117,746	97,291	5.75	16,920
2000	255,186.57	176,079	135,318	119,869	6.20	19,334
2001	88,075.96	58,703	45,114	42,962	6.67	6,441
2002	125,758.95	80,737	62,047	63,712	7.16	8,898
2003	185,822.47	114,374	87,897	97,925	7.69	12,734
2004	173,877.61	102,327	78,639	95,239	8.23	11,572
2005	256,475.71	143,626	110,378	146,098	8.80	16,602
2006	243,700.67	129,161	99,261	144,440	9.40	15,366
2007	26,774.06	13,360	10,267	16,507	10.02	1,647
2008	64,946.93	30,330	23,309	41,638	10.66	3,906
2009	49,428.37	21,452	16,486	32,942	11.32	2,910
2010	141,376.35	56,551	43,460	97,916	12.00	8,160
2012	303,247.13	99,920	76,789	226,458	13.41	16,887
2013	242,215.31	70,969	54,540	187,675	14.14	13,273
2014	232,404.96	59,496	45,723	186,682	14.88	12,546
2015	266,546.02	58,107	44,656	221,890	15.64	14,187
2016	461,627.85	83,093	63,858	397,770	16.40	24,254
2017	335,528.75	47,310	36,358	299,171	17.18	17,414
2018	650,041.41	65,979	50,705	599,336	17.97	33,352
2019	715,470.59	43,644	33,541	681,930	18.78	36,312
2020	830,231.78	17,020	13,080	817,152	19.59	41,713
	11,764,061.66	6,622,460	5,127,986	6,636,076		1,030,664

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.4   8.76

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 370.01 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-R1.5						
NET SALVAGE PERCENT.. 0						
2007	2,144,841.56	1,070,276	836,223	1,308,619	10.02	130,601
2008	214,423.20	100,136	78,238	136,185	10.66	12,775
2009	151,893.37	65,922	51,506	100,387	11.32	8,868
2010	204,049.77	81,620	63,771	140,279	12.00	11,690
2012	356,825.21	117,574	91,862	264,963	13.41	19,759
2013	263,441.75	77,188	60,308	203,134	14.14	14,366
2014	240,125.54	61,472	48,029	192,097	14.88	12,910
2015	302,604.47	65,968	51,542	251,062	15.64	16,053
2016	420,606.20	75,709	59,153	361,453	16.40	22,040
2017	538,372.94	75,911	59,311	479,062	17.18	27,885
2018	839,238.60	85,183	66,555	772,684	17.97	42,999
2019	712,863.06	43,485	33,975	678,888	18.78	36,150
2020	776,479.08	15,918	12,437	764,042	19.59	39,002
	7,165,764.75	1,936,362	1,512,910	5,652,855		395,098

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.3 5.51

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-L0						
NET SALVAGE PERCENT.. -10						
1954	249.55	275	275			
1959	1,022.06	1,124	1,124			
1962	2,036.01	2,104	1,723	517	0.91	517
1963	3,244.28	3,331	2,728	841	1.00	841
1964	1,572.99	1,601	1,311	419	1.12	374
1965	1,585.22	1,600	1,310	434	1.24	350
1966	1,874.80	1,875	1,535	527	1.36	388
1967	1,957.69	1,941	1,589	564	1.48	381
1968	3,610.47	3,545	2,903	1,069	1.61	664
1969	2,179.53	2,121	1,737	660	1.73	382
1970	1,602.17	1,544	1,264	498	1.86	268
1971	453.99	433	355	144	1.98	73
1972	1,508.85	1,426	1,168	492	2.11	233
1973	1,611.65	1,507	1,234	539	2.25	240
1974	2,016.31	1,866	1,528	690	2.38	290
1975	1,225.14	1,121	918	430	2.52	171
1976	2,434.61	2,203	1,804	874	2.66	329
1977	3,955.18	3,539	2,898	1,453	2.80	519
1978	1,353.81	1,196	979	510	2.95	173
1979	5,698.94	4,977	4,076	2,193	3.09	710
1980	5,770.64	4,977	4,076	2,272	3.24	701
1981	3,686.39	3,136	2,568	1,487	3.40	437
1982	5,244.11	4,399	3,602	2,167	3.56	609
1983	6,926.09	5,729	4,691	2,928	3.72	787
1984	5,302.52	4,324	3,541	2,292	3.88	591
1985	1,136.10	912	747	503	4.05	124
1986	4,011.51	3,171	2,597	1,816	4.22	430
1987	5,159.47	4,014	3,287	2,388	4.39	544
1988	1,370.23	1,048	858	649	4.57	142
1989	3,901.00	2,929	2,399	1,892	4.76	397
1990	5,912.32	4,362	3,572	2,932	4.94	594
1991	6,220.23	4,498	3,683	3,159	5.14	615
1992	17,519.47	12,424	10,174	9,097	5.33	1,707
1993	13,506.14	9,370	7,673	7,184	5.54	1,297
1994	18,574.48	12,613	10,329	10,103	5.74	1,760
1995	18,947.40	12,561	10,286	10,556	5.96	1,771
1996	5,044.94	3,263	2,672	2,877	6.18	466
1997	18,591.79	11,725	9,601	10,850	6.40	1,695
1998	9,219.77	5,652	4,628	5,514	6.64	830
1999	13,774.30	8,212	6,725	8,427	6.87	1,227
2000	17,077.23	9,868	8,081	10,704	7.12	1,503
2001	12,337.45	6,903	5,653	7,918	7.37	1,074
2002	21,143.15	11,412	9,345	13,912	7.64	1,821

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-L0						
NET SALVAGE PERCENT.. -10						
2003	22,634.53	11,785	9,651	15,247	7.90	1,930
2004	37,486.68	18,748	15,352	25,883	8.18	3,164
2005	28,486.15	13,641	11,170	20,165	8.47	2,381
2006	33,690.71	15,417	12,625	24,435	8.76	2,789
2007	30,466.01	13,249	10,849	22,664	9.07	2,499
2008	42,231.50	17,374	14,227	32,228	9.39	3,432
2009	44,496.68	17,262	14,136	34,810	9.71	3,585
2010	69,327.64	25,166	20,608	55,652	10.05	5,538
2011	82,827.12	27,941	22,880	68,230	10.40	6,561
2012	220,316.30	68,504	56,097	186,251	10.76	17,310
2013	155,388.39	44,099	36,112	134,815	11.13	12,113
2014	126,450.82	32,270	26,425	112,671	11.52	9,780
2015	174,342.77	39,251	32,142	159,635	11.93	13,381
2016	254,242.31	49,221	40,306	239,361	12.36	19,366
2017	149,908.41	23,856	19,536	145,363	12.83	11,330
2018	245,634.01	29,722	24,339	245,858	13.35	18,416
2019	244,460.31	19,361	15,854	253,052	13.92	18,179
2020	180,406.83	5,424	4,442	194,006	14.59	13,297
	2,404,367.15	659,122	539,998	2,104,806		193,076

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.9 8.03

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

SURVIVOR CURVE.. IOWA 20-L0
NET SALVAGE PERCENT.. -10

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1939	77.10	85	85			
1941	264.19	276	291			
1949	104.70	104	115			
1950	2,456.56	2,421	2,702			
1952	1,614.44	1,569	1,776			
1953	555.82	537	611			
1954	4,954.46	4,747	5,450			
1958	4,653.21	4,323	5,119			
1959	1,311.37	1,209	1,443			
1960	381.84	349	420			
1961	828.58	751	911			
1962	5,017.25	4,509	5,519			
1963	1,599.01	1,424	1,759			
1964	980.50	866	1,079			
1965	15.91	14	18			
1966	1,263.75	1,095	1,390			
1967	6,561.38	5,630	7,218			
1968	5,269.75	4,475	5,797			
1969	6,624.11	5,571	7,287			
1970	10,847.58	9,027	11,932			
1971	25,104.59	20,656	27,615			
1972	6,642.80	5,407	7,307			
1973	23,933.61	19,258	26,327			
1974	2,062.25	1,640	2,268			
1975	4,635.60	3,643	5,099			
1976	5,828.42	4,523	6,411			
1977	31,991.63	24,510	35,191			
1978	9,653.44	7,300	10,619			
1979	16,301.99	12,167	17,932			
1980	7,283.50	5,360	8,012			
1981	28,082.12	20,357	30,890			
1982	12,932.61	9,240	14,226			
1983	8,055.76	5,667	8,861			
1984	6,345.22	4,390	6,980			
1985	14,362.98	9,780	15,799			
1986	32,603.95	21,806	35,864			
1987	12,533.90	8,238	13,787			
1988	59,205.57	38,196	65,126			
1989	42,206.19	26,695	46,427			
1990	36,451.55	22,594	40,097			
1991	54,429.92	33,020	59,873			
1992	60,947.90	36,170	67,043			
1993	67,315.06	39,060	74,047			

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-L0						
NET SALVAGE PERCENT.. -10						
1994	132,252.46	74,921	145,478			
1995	172,344.02	95,168	189,578			
1996	85,479.70	45,980	94,028			
1997	48,088.52	25,153	52,897			
1998	53,106.19	26,959	58,417			
1999	97,520.42	48,004	107,272			
2000	85,767.26	40,851	94,344			
2001	86,359.89	39,708	94,996			
2002	72,679.92	32,219	79,948			
2003	75,334.35	32,111	82,868			
2004	70,069.89	28,634	77,077			
2005	107,373.47	41,988	118,111			
2006	103,307.66	38,467	112,481	1,157	13.23	87
2007	140,755.16	49,778	145,556	9,275	13.57	683
2008	94,989.92	31,765	92,884	11,605	13.92	834
2009	127,130.70	39,925	116,745	23,099	14.29	1,616
2010	118,511.06	34,807	101,779	28,583	14.66	1,950
2011	58,865.50	16,059	46,958	17,794	15.04	1,183
2012	79,902.21	20,083	58,725	29,167	15.43	1,890
2013	137,358.16	31,428	91,898	59,196	15.84	3,737
2014	150,802.50	31,020	90,705	75,178	16.26	4,623
2015	126,303.89	22,855	66,830	72,104	16.71	4,315
2016	158,338.71	24,471	71,556	102,617	17.19	5,970
2017	115,420.97	14,537	42,508	84,455	17.71	4,769
2018	233,403.98	22,337	65,315	191,429	18.26	10,484
2019	150,631.43	9,279	27,133	138,562	18.88	7,339
2020	74,564.48	1,681	4,915	77,106	19.59	3,936
	3,580,954.49	1,348,847	3,017,725	921,325		53,416

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 17.2   1.49

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

SURVIVOR CURVE.. IOWA 55-R3
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1955	109,709.17	95,627	90,772	18,937	7.06	2,682
1962	55,562.00	45,904	43,573	11,989	9.56	1,254
1965	464.00	372	353	111	10.86	10
1966	511,384.98	406,040	385,424	125,961	11.33	11,117
1967	2,535.00	1,990	1,889	646	11.82	55
1971	1,239.60	925	878	362	13.94	26
1972	12,861.19	9,468	8,987	3,874	14.51	267
1973	51,740.04	37,535	35,629	16,111	15.10	1,067
1974	7,011.97	5,009	4,755	2,257	15.71	144
1977	352.00	239	227	125	17.61	7
1978	56,043.94	37,427	35,527	20,517	18.27	1,123
1979	50,910.48	33,379	31,684	19,226	18.94	1,015
1980	369,179.40	237,416	225,362	143,817	19.63	7,326
1981	15,059.53	9,493	9,011	6,049	20.33	298
1982	14,308.58	8,835	8,386	5,923	21.04	282
1983	8,793.91	5,313	5,043	3,751	21.77	172
1984	25,183.02	14,881	14,125	11,058	22.50	491
1985	52,641.08	30,388	28,845	23,796	23.25	1,023
1986	34,583.52	19,486	18,497	16,087	24.01	670
1987	146,732.58	80,650	76,555	70,178	24.77	2,833
1988	105,755.53	56,627	53,752	52,004	25.55	2,035
1989	97,791.19	50,958	48,371	49,420	26.34	1,876
1990	53,978.52	27,343	25,955	28,024	27.14	1,033
1991	25,091.91	12,345	11,718	13,374	27.94	479
1992	18,726.45	8,934	8,480	10,246	28.76	356
1993	102,157.77	47,197	44,801	57,357	29.59	1,938
1994	162,949.10	72,824	69,127	93,822	30.42	3,084
1995	111,068.37	47,942	45,508	65,560	31.26	2,097
1996	77,657.54	32,320	30,679	46,979	32.11	1,463
1997	229,785.39	92,041	87,368	142,417	32.97	4,320
1998	134,286.85	51,664	49,041	85,246	33.84	2,519
1999	6,864.50	2,531	2,402	4,462	34.72	129
2000	58,466.58	20,623	19,576	38,891	35.60	1,092
2001	15,027.92	5,058	4,801	10,227	36.49	280
2002	15,075.24	4,827	4,582	10,493	37.39	281
2003	9,593.03	2,913	2,765	6,828	38.30	178
2004	124,808.09	35,831	34,012	90,796	39.21	2,316
2005	48,595.00	13,138	12,471	36,124	40.13	900
2006	57,941.50	14,685	13,939	44,002	41.06	1,072
2007	33,327.72	7,884	7,484	25,844	41.99	615
2008	274,845.55	60,315	57,253	217,593	42.93	5,069
2009	122,764.60	24,843	23,582	99,183	43.87	2,261
2010	9,453.97	1,752	1,663	7,791	44.81	174

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
NET SALVAGE PERCENT.. 0						
2011	81,651.41	13,703	13,007	68,644	45.77	1,500
2012	55,802.93	8,401	7,974	47,829	46.72	1,024
2013	20,031.81	2,662	2,527	17,505	47.69	367
2014	190,651.91	22,011	20,893	169,759	48.65	3,489
2015	31,371.82	3,069	2,913	28,459	49.62	574
2016	26,053.00	2,089	1,983	24,070	50.59	476
2017	283,665.54	17,689	16,791	266,875	51.57	5,175
2019	44,698.45	1,203	1,142	43,556	53.52	814
2020	14,958,026.95	133,276	126,510	14,831,517	54.51	272,088
	19,114,262.13	1,979,075	1,878,592	17,235,670		352,936

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 48.8   1.85

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 391.01 OFFICE FURNITURE AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1984	3,570.53	3,571	3,571			
1985	15,576.43	15,576	15,576			
1986	4,865.80	4,866	4,866			
1987	2,709.87	2,710	2,710			
1988	6,799.16	6,799	6,799			
1989	9,361.83	9,362	9,362			
1990	3,044.56	3,045	3,045			
1991	2,000.07	2,000	2,000			
1992	2,213.87	2,214	2,214			
1993	2,017.40	2,017	2,017			
1994	16,172.84	16,173	16,173			
1995	2,856.76	2,857	2,857			
1996	8,661.72	8,662	8,662			
1997	22,611.96	22,612	22,612			
1998	3,201.14	3,201	3,201			
1999	10,450.23	10,450	10,450			
2000	5,093.09	5,093	5,093			
2001	3,018.26	3,018	3,018			
2002	2,537.21	2,537	2,537			
2003	167.99	168	168			
2004	10,772.98	10,773	10,773			
2005	1,783.70	1,784	1,783			
	139,487.40	139,488	139,487			
AMORTIZED						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2006	209.98	203	203	7	0.50	7
2007	13,765.30	12,389	12,389	1,377	1.50	918
2008	20,699.88	17,250	17,250	3,450	2.50	1,380
2009	32,063.15	24,582	24,581	7,482	3.50	2,138
2010	17,031.55	11,922	11,922	5,110	4.50	1,136
2011	17,161.88	10,869	10,869	6,293	5.50	1,144
2012	2,712.89	1,537	1,537	1,176	6.50	181
2013	7,980.17	3,990	3,990	3,990	7.50	532
2014	15,511.10	6,721	6,721	8,790	8.50	1,034
2015	751.97	276	276	476	9.50	50
2016	4,296.17	1,289	1,289	3,007	10.50	286
2017	2,932.90	684	684	2,249	11.50	196

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 391.01 OFFICE FURNITURE AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
AMORTIZED						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2018	4,621.59	770	770	3,852	12.50	308
2019	168,229.15	16,823	16,823	151,407	13.50	11,215
2020	842,421.76	28,078	28,077	814,344	14.50	56,162
	1,150,389.44	137,383	137,380	1,013,009		76,687
	1,289,876.84	276,871	276,867	1,013,009		76,687

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.2 5.95

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 393.00 STORES EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1987	16,224.76	16,225	16,225			
1989	1,087.44	1,087	1,087			
1991	855.00	855	855			
1995	32,732.00	32,732	32,732			
	50,899.20	50,899	50,899			
AMORTIZED						
SURVIVOR CURVE.. 25-SQUARE						
NET SALVAGE PERCENT.. 0						
1996	632.50	620	618	15	0.50	15
1997	526.78	495	493	34	1.50	23
2000	722.23	592	590	132	4.50	29
2001	637.29	497	495	142	5.50	26
2003	279.59	196	195	84	7.50	11
2004	26,109.93	17,233	17,170	8,940	8.50	1,052
2008	100.73	50	50	51	12.50	4
2020	10,748.29	215	214	10,534	24.50	430
	39,757.34	19,898	19,825	19,932		1,590
	90,656.54	70,797	70,724	19,932		1,590

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.5   1.75

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 394.00 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1985	34,759.08	34,759	34,759			
1986	26,775.97	26,776	26,776			
1987	24,136.58	24,137	24,137			
1988	24,307.41	24,307	24,307			
1989	21,496.18	21,496	21,496			
1990	46,885.28	46,885	46,885			
1991	26,811.89	26,812	26,812			
1992	62,513.26	62,513	62,513			
1993	20,334.18	20,334	20,334			
1994	41,845.03	41,845	41,845			
1995	37,878.32	37,878	37,878			
	367,743.18	367,742	367,743			
AMORTIZED						
SURVIVOR CURVE.. 25-SQUARE						
NET SALVAGE PERCENT.. 0						
1996	48,012.00	47,052	46,732	1,280	0.50	1,280
1997	34,310.31	32,252	32,033	2,278	1.50	1,519
1998	62,757.17	56,481	56,097	6,660	2.50	2,664
1999	35,494.28	30,525	30,317	5,177	3.50	1,479
2000	44,380.16	36,392	36,145	8,236	4.50	1,830
2001	30,333.17	23,660	23,499	6,834	5.50	1,243
2002	52,604.11	38,927	38,662	13,942	6.50	2,145
2003	49,595.54	34,717	34,481	15,115	7.50	2,015
2004	37,681.20	24,870	24,701	12,980	8.50	1,527
2005	27,437.77	17,011	16,895	10,542	9.50	1,110
2006	50,963.70	29,559	29,358	21,606	10.50	2,058
2007	79,341.39	42,844	42,553	36,789	11.50	3,199
2008	61,675.16	30,838	30,628	31,047	12.50	2,484
2009	97,033.69	44,635	44,331	52,702	13.50	3,904
2010	116,208.99	48,808	48,476	67,733	14.50	4,671
2011	75,796.79	28,803	28,607	47,190	15.50	3,045
2012	72,243.58	24,563	24,396	47,848	16.50	2,900
2013	61,196.94	18,359	18,234	42,963	17.50	2,455
2014	67,788.76	17,625	17,505	50,284	18.50	2,718
2015	89,700.78	19,734	19,600	70,101	19.50	3,595
2016	125,877.64	22,658	22,504	103,374	20.50	5,043
2017	292,360.28	40,930	40,652	251,709	21.50	11,707

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 394.00 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
AMORTIZED						
SURVIVOR CURVE.. 25-SQUARE						
NET SALVAGE PERCENT.. 0						
2018	70,843.14	7,084	7,036	63,807	22.50	2,836
2019	239,107.81	14,346	14,248	224,859	23.50	9,568
2020	139,404.19	2,788	2,769	136,635	24.50	5,577
	2,062,148.55	735,461	730,460	1,331,689		82,572
	2,429,891.73	1,103,203	1,098,203	1,331,689		82,572

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 16.1   3.40

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 395.00 LABORATORY EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1984	63,066.07	63,066	63,066			
1985	9,049.24	9,049	9,049			
1986	3,681.44	3,681	3,681			
1987	6,939.02	6,939	6,939			
1988	49,312.50	49,312	49,313			
1989	24,459.69	24,460	24,460			
1990	7,340.66	7,341	7,341			
1991	6,030.23	6,030	6,030			
1992	19,599.49	19,599	19,599			
1993	18,837.52	18,838	18,838			
1994	21,260.97	21,261	21,261			
1995	15,597.34	15,597	15,597			
	245,174.17	245,173	245,174			
AMORTIZED						
SURVIVOR CURVE.. 25-SQUARE						
NET SALVAGE PERCENT.. 0						
1996	14,002.46	13,722	13,636	367	0.50	367
1997	4,298.90	4,041	4,016	283	1.50	189
1998	21,648.53	19,484	19,361	2,287	2.50	915
1999	7,119.75	6,123	6,085	1,035	3.50	296
2000	3,427.17	2,810	2,792	635	4.50	141
2001	34,532.93	26,936	26,767	7,766	5.50	1,412
2002	6,372.25	4,715	4,685	1,687	6.50	260
2003	2,187.80	1,531	1,521	666	7.50	89
2004	13,671.65	9,023	8,966	4,705	8.50	554
2005	21,387.66	13,260	13,177	8,211	9.50	864
2006	12,046.30	6,987	6,943	5,103	10.50	486
2007	38,523.43	20,803	20,672	17,851	11.50	1,552
2008	12,073.36	6,037	5,999	6,074	12.50	486
2009	8,793.94	4,045	4,020	4,774	13.50	354
2010	17,140.77	7,199	7,154	9,987	14.50	689
2011	43,410.08	16,496	16,392	27,018	15.50	1,743
2012	37,354.73	12,701	12,621	24,734	16.50	1,499
2013	37,377.15	11,213	11,142	26,235	17.50	1,499
2014	143,124.88	37,212	36,978	106,147	18.50	5,738
2015	84,085.28	18,499	18,383	65,703	19.50	3,369
2016	16,927.53	3,047	3,028	13,900	20.50	678
2017	28,375.31	3,973	3,948	24,427	21.50	1,136

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 395.00 LABORATORY EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
AMORTIZED						
SURVIVOR CURVE.. 25-SQUARE						
NET SALVAGE PERCENT.. 0						
2018	11,861.32	1,186	1,179	10,683	22.50	475
2019	79,841.90	4,791	4,761	75,081	23.50	3,195
2020	3,771.07	75	75	3,697	24.50	151
	703,356.15	255,909	254,300	449,056		28,137
	948,530.32	501,082	499,474	449,056		28,137

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 16.0 2.97

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 397.00 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1980	7,076.21	7,076	7,076			
1981	13,555.97	13,556	13,556			
1982	4,207.00	4,207	4,207			
1983	74,862.00	74,862	74,862			
1984	52,401.61	52,402	52,402			
1985	109,693.05	109,693	109,693			
1986	49,990.67	49,991	49,991			
1987	5,405.49	5,405	5,405			
1988	24,875.32	24,875	24,875			
1989	30,312.67	30,313	30,313			
1990	18,349.82	18,350	18,350			
1991	43,874.04	43,874	43,874			
1992	121,589.92	121,590	121,590			
1993	8,900.74	8,901	8,901			
1994	97,893.69	97,894	97,894			
1995	46,517.23	46,517	46,517			
1996	90,831.56	90,832	90,832			
1997	47,162.03	47,162	47,162			
1998	46,154.13	46,154	46,154			
1999	206,699.18	206,699	206,699			
2000	156,808.60	156,809	156,809			
2001	11,680.00	11,680	11,680			
2002	278,007.18	278,007	278,007			
2003	92,581.13	92,581	92,581			
2004	16,948.53	16,949	16,949			
2005	91,076.31	91,076	91,076			
	1,747,454.08	1,747,455	1,747,454			
AMORTIZED						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2006	110,115.54	106,445	105,888	4,227	0.50	4,227
2007	708,598.99	637,739	634,402	74,197	1.50	49,465
2008	29,652.50	24,710	24,581	5,072	2.50	2,029
2009	513,353.44	393,573	391,514	121,840	3.50	34,811
2010	84,700.11	59,290	58,980	25,720	4.50	5,716
2011	57,608.13	36,485	36,294	21,314	5.50	3,875
2012	28,629.59	16,224	16,139	12,490	6.50	1,922
2013	15,560.44	7,780	7,739	7,821	7.50	1,043
2014	67,376.82	29,196	29,043	38,334	8.50	4,510

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 397.00 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
AMORTIZED						
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2015	94,104.22	34,505	34,324	59,780	9.50	6,293
2016	72,024.75	21,607	21,494	50,531	10.50	4,812
2017	464,828.39	108,458	107,891	356,938	11.50	31,038
2018	45,439.14	7,573	7,533	37,906	12.50	3,032
2019	204,076.29	20,408	20,301	183,775	13.50	13,613
2020	762,045.50	25,399	25,266	736,779	14.50	50,812
	3,258,113.85	1,529,392	1,521,390	1,736,724		217,198
	5,005,567.93	3,276,847	3,268,844	1,736,724		217,198

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.0 4.34

UNITIL ENERGY SYSTEMS, INC.

ACCOUNT 398.00 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AT DECEMBER 31, 2020

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
NET SALVAGE PERCENT.. 0						
1984	1,171.50	1,172	1,172			
1986	521.09	521	521			
1987	417.13	417	417			
1989	495.00	495	495			
1990	73.69	74	74			
1993	9,599.93	9,600	9,600			
1994	567.53	568	568			
1995	438.00	438	438			
1999	23,655.64	23,656	23,656			
2000	46,775.63	46,776	46,775			
	83,715.14	83,717	83,715			
AMORTIZED						
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2001	602.99	588	587	16	0.50	16
2002	8,596.29	7,952	7,934	662	1.50	441
2005	8,956.41	6,941	6,926	2,031	4.50	451
2007	872.52	589	588	285	6.50	44
2009	122.57	70	70	53	8.50	6
2010	77.49	41	41	37	9.50	4
	19,228.27	16,181	16,145	3,083		962
	102,943.41	99,898	99,860	3,083		962

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.2 0.93

UNITIL ENERGY SYSTEMS, INC.

COMPARISON OF CURRENT ANNUAL DEPRECIATION EXPENSE VS. PROPOSED ANNUAL DEPRECIATION EXPENSE AS OF DECEMBER 31, 2020

			CURRENT				PROPOSED				
	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2020	SURVIVOR CURVE	NET SALVAGE PERCENT	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	SURVIVOR CURVE	NET SALVAGE PERCENT	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	INCREASE/ (DECREASE)
	(1)	(2)	(3)	(4)	(5)=(6)*(2)	(6)	(7)	(8)	(9)	(10)	(11)
	ELECTRIC PLANT										
	PRODUCTION PLANT										
343.00	PRIME MOVERS	56,575.22	15-S3	0.0	3,774	6.67	10-S3	0	10,559	18.66	6,785
	TOTAL PRODUCTION PLANT	**56,575.22**			**3,774**	**6.67**			**10,559**	**18.66**	**6,785**
	DISTRIBUTION PLANT										
361.00	STRUCTURES AND IMPROVEMENTS	2,173,616.44	52-L1.5	(27.5)	53,254	2.45	55-R4	(30)	52,132	2.40	(1,122)
362.00	STATION EQUIPMENT	50,412,131.73	51-S1.5 *	(32.5)	1,310,715	2.60	49-R1.5	(40)	1,492,423	2.96	181,708
364.00	POLES, TOWERS AND FIXTURES	75,140,860.60	41-S1 *	(51.5)	2,780,212	3.70	50-R1.5	(80)	2,709,085	3.61	(71,127)
365.00	OVERHEAD CONDUCTORS AND DEVICES	92,313,722.86	39-L1 *	(42.0)	3,360,220	3.64	45-R0.5	(65)	3,343,998	3.62	(16,222)
366.00	UNDERGROUND CONDUIT	2,587,958.32	56-R2.5 *	(14.5)	52,794	2.04	60-R2.5	(25)	55,787	2.16	2,993
367.00	UNDERGROUND CONDUCTORS AND DEVICES	23,862,963.47	52-R1.5 *	(32.5)	608,506	2.55	55-R2.5	(50)	679,570	2.85	71,064
368.00	LINE TRANSFORMERS	29,259,308.24	35-R3 *	(5.0)	877,779	3.00	40-R1.5	(10)	720,501	2.46	(157,278)
368.01	LINE TRANSFORMER INSTALLATIONS	25,947,042.32	35-R3 *	(1.0)	749,870	2.89	40-R1.5	0	596,350	2.30	(153,520)
369.00	SERVICES	25,642,632.28	27-R3 *	(53.0)	1,453,937	5.67	40-R2	(50)	623,537	2.43	(830,400)
370.00	METERS	11,764,061.66	20-S3	0.0	588,203	5.00	20-R1.5	0	1,030,664	8.76	442,461
370.01	METER INSTALLATIONS	7,165,764.75	20-S3	0.0	358,288	5.00	20-R1.5	0	395,098	5.51	36,810
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES	2,404,367.15	17-S0.5	(28.5)	181,770	7.56	15-L0	(10)	193,076	8.03	11,306
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	3,580,954.49	17-R1	(32.5)	278,956	7.79	20-L0	(10)	53,416	1.49	(225,540)
	TOTAL DISTRIBUTION PLANT	**352,255,384.31**			**12,654,504**	**3.59**			**11,945,637**	**3.39**	**(708,867)**
	GENERAL PLANT										
390.00	STRUCTURES AND IMPROVEMENTS	19,114,262.13	43-R2.5	10.5	397,577	2.08	55-R3	0	352,936	1.85	(44,641)
391.01	OFFICE FURNITURE AND EQUIPMENT										
	FULLY ACCRUED	139,487.40	15-L2	12.5	8,132	5.83			0	-	(8,132)
	AMORTIZED	1,150,389.44	15-L2	12.5	67,068	5.83	15-SQ	0	76,687	6.67	9,619
	TOTAL ACCOUNT 391.01	1,289,876.84			75,200				76,687		1,487
393.00	STORES EQUIPMENT										
	FULLY ACCRUED	50,899.20	29-R5	2.5	1,710	3.36			0	-	(1,710)
	AMORTIZED	39,757.34	29-R5	2.5	1,336	3.36	25-SQ	0	1,590	4.00	254
	TOTAL ACCOUNT 393.00	90,656.54			3,046				1,590		(1,456)
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT										
	FULLY ACCRUED	367,743.18	28-R2	9.0	13,386	3.64			0	-	(13,386)
	AMORTIZED	2,062,148.55	28-R2	9.0	75,062	3.64	25-SQ	0	82,572	4.00	7,510
	TOTAL ACCOUNT 394.00	2,429,891.73			88,448				82,572		(5,876)
395.00	LABORATORY EQUIPMENT										
	FULLY ACCRUED	245,174.17	25-SQ	2.5	9,562	3.90			0	-	(9,562)
	AMORTIZED	703,356.15	25-SQ	2.5	27,431	3.90	25-SQ	0	28,137	4.00	706
	TOTAL ACCOUNT 395.00	948,530.32			36,993				28,137		(8,856)

UNITIL ENERGY SYSTEMS, INC.

COMPARISON OF CURRENT ANNUAL DEPRECIATION EXPENSE VS. PROPOSED ANNUAL DEPRECIATION EXPENSE AS OF DECEMBER 31, 2020

			CURRENT				PROPOSED				
	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2020	SURVIVOR CURVE	NET SALVAGE PERCENT	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	SURVIVOR CURVE	NET SALVAGE PERCENT	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	INCREASE/ (DECREASE)
	(1)	(2)	(3)	(4)	(5)=(6)*(2)	(6)	(7)	(8)	(9)	(10)	(11)
397.00	COMMUNICATION EQUIPMENT										
	FULLY ACCRUED	1,747,454.08	12-S3	1.0	115,332	6.60			0	-	(115,332)
	AMORTIZED	3,258,113.85	12-S3	1.0	215,036	6.60	15-SQ	0	217,198	6.67	2,162
	TOTAL ACCOUNT 397.00	5,005,567.93			330,368				217,198		(113,170)
398.00	MISCELLANEOUS EQUIPMENT										
	FULLY ACCRUED	83,715.14	20-R4	2.5	4,085	4.88			0	-	(4,085)
	AMORTIZED	19,228.27	20-R4	2.5	938	4.88	20-SQ	0	962	5.00	24
	TOTAL ACCOUNT 398.00	102,943.41			5,023				962		(4,061)
	TOTAL GENERAL PLANT	**28,981,728.90**			**936,655**	**3.23**			**760,082**	**2.62**	**(176,573)**
	RESERVE ADJUSTMENT FOR AMORTIZATION										
390.01	STRUCTURES AND IMPROVEMENTS - MISCELLANEOUS								(173) **		(173)
391.01	OFFICE FURNITURE AND EQUIPMENT								66,592 **		66,592
391.03	OFFICE FURNITURE AND EQUIPMENT - COMPUTER EQUIPMENT								(869) **		(869)
393.00	STORES EQUIPMENT								908 **		908
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT								22,424 **		22,424
395.00	LABORATORY EQUIPMENT								58 **		58
397.00	COMMUNICATION EQUIPMENT								(1,754) **		(1,754)
398.00	MISCELLANEOUS EQUIPMENT								(617) **		(617)
	TOTAL RESERVE ADJUSTMENT FOR AMORTIZATION								**86,569**		**86,569**
	TOTAL DEPRECIABLE PLANT	**381,293,688.43**			**13,594,933**	**3.57**			**12,802,847**	**3.36**	**(792,086)**
	NONDEPRECIABLE PLANT										
301.00	ORGANIZATION	380.00									
303.00	MISCELLANEOUS INTANGIBLE PLANT - 5 YEAR	6,638,390.64									
303.01	MISCELLANEOUS INTANGIBLE PLANT - 3 YEAR	87,195.82									
303.02	MISCELLANEOUS INTANGIBLE PLANT - 10 YEAR	5,489,895.89									
360.01	RIGHTS OF WAY	1,002,659.97									
360.02	RIGHTS OF WAY	1,674,812.39									
389.00	LAND	1,363,295.15									
392.00	TRANSPORTATION EQUIPMENT	1,073,516.64									
	TOTAL NONDEPRECIABLE PLANT	**17,330,146.50**									
	TOTAL ELECTRIC PLANT	**398,623,834.93**									

* ADOPTED IN SETTLEMENT. CURVE TYPE WAS NOT SPECIFIED IN SETTLEMENT BUT ASSUMED TO BE THE SAME CURVE TYPE AS PREVIOUSLY PROPOSED.
** 5-YEAR AMORTIZATION OF RESERVE ADJUSTMENT RELATED TO IMPLEMENTATION OF AMORTIZATION ACCOUNTING.

UNITIL ENERGY SYSTEMS, INC.

Supplementary Filing Requirements

In accordance with New Hampshire Code of Administrative Rules Part Puc 1604, Full Rate Case Filing Requirements, 1604.01 (a), Unitil Energy Systems, Inc. (“Company” or “UES”) has prepared responses to the following requests as provided herein:

(11) (000070) A detailed list of all membership fees, dues, lobbying expenses and donations for the test year charged above the line showing the trade, technical, and professional associations and organizations and amount, and the account charged, according to the following guidelines:

a. If the utility's annual gross revenues are less than $100,000,000 all membership fees, dues and donations shall be reported; and

b. If the utility's annual gross revenues are $100,000,000 or more, all membership fees, dues and donations of $5,000 and more shall be reported;

(12) (000071) The utility's most recent depreciation study if not previously filed in an adjudicative proceeding;

(13) (000072) The utility's most recent management and financial audits if not previously filed in an adjudicative proceeding;

(14) (000105) A list of officers and directors of the utility and their full compensation for each of the last 2 years, detailing base compensation, bonuses, and incentive plans;

(15) (000108) Copies of all officer and executive incentive plans;

(16) (000128) Lists of the amount of voting stock of the utility categorized as follows:

a. Owned by an officer or director individually;

b. Owned by the spouse or minor child of an officer or director; or

c. Controlled by the officer or director directly or indirectly;

(17) (000129) A list of all payments to individuals or corporations for contractual services in the test year with a description of the purpose of the contractual services, as follows:

a. For utilities with less than $10,000,000 in annual gross revenues, a list of all payments in excess of $10,000;

b. For utilities with $10,000,001 to $100,000,000 in annual gross revenues, a list of all payments in excess of $50,000; and

c. For utilities with annual gross revenues in excess of $100,000,000, a list of all payments in excess of $100,000;

d. The reporting thresholds for a particular entity shall be on a cumulative basis, indicating the number of items comprising the total amount of expenditure.

(18) (000131) For non-utility operations, the amount of assets and costs allocated thereto and justification for such allocations;

(19) (000132) Balance sheets and income statements for the previous 2 years if not previously filed with the commission;

(20) (000133) Quarterly income statements for the previous 2 years if not previously filed with the commission;

(21) (000135) Quarterly sales volumes for the previous 2 years, itemized for residential and other classifications of service, if not previously filed with the commission;

(22) (000137) A description of the utility's projected need for external capital for the 2 year period immediately following the test year;

(23) (000138) The utility's capital budget with a statement of the source and uses of funds for the 2 years immediately following the test year;

(24) (000140) The amount of outstanding short term debt, on a monthly basis during the test year, for each short-term indebtedness;

(25) (000142) If a utility is a subsidiary, a certificate of an appropriate official of the subsidiary detailing any expense of the parent company which was included in the subsidiary's cost of service;

(26) (000144) Support for figures appearing on written testimony and in accompanying exhibits.

(1) The utility's internal financial reports for the following periods:

a. For the first and last month of the test year;

b. For the entire test year; and

c. For the 12 months or 5 quarters prior to the test year;

Response:

Please see PUC 1604.01(a) – 01 Attachment 1 for the internal financial reports (balance sheets and income statements) for the above requested periods.

1604.01(a) - 01 Attachment 1
Page 1 of 3

UNITIL ENERGY SYSTEMS, INC.
Income Statement
G_UES_IS_Rate_Case

Schedule 3
2/25/2021
For Periods Ending December 31, 2020

	YTD December 2019	MTD January 2020	MTD December 2020	YTD December 2020
OPERATING REVENUES				
Electric Service Revenue:				
Residential (440)	$85,554,125.28	$8,753,499.64	$7,939,107.52	$89,662,319.15
General Service (442)	64,886,861.11	5,716,348.18	5,529,156.14	63,811,082.78
Public Street Light (444)	2,468,924.30	208,381.13	200,917.53	2,422,297.89
Sales to Public Auth (445)	9,493.08	296.37	366.08	7,544.83
Sales for Resale (447)	2,428,365.23	236,923.18	321,554.35	1,521,143.91
Other Sales (449)	4,057,392.96	(1,197,908.01)	2,211,529.00	(597,808.32)
Total Electric Service Revenue	159,405,161.96	13,717,540.49	16,202,630.62	156,826,580.24
Other Operating Revenues:				
Late Payment Charges (450)	275,537.40	34,968.67	0.00	94,599.56
Misc. Service Revenues (451)	280,977.62	18,214.10	12,885.00	194,995.78
Rent-elect. Property (454)	557,800.46	47,394.73	49,697.15	585,199.80
Other Electric Rev (456)	1,312,348.36	154,900.95	71,417.51	1,222,079.94
Total Other Operating Revenues	2,426,663.84	255,478.45	133,999.66	2,096,875.08
TOTAL OPERATING REVENUES	161,831,825.80	13,973,018.94	16,336,630.28	158,923,455.32
OPERATING EXPENSES				
Operation & Maint. Expenses:				
Purchased Power (555, 557)	65,370,883.84	6,803,005.74	5,424,164.02	53,005,520.74
Transmission (556, 560-579)	28,323,204.45	2,333,607.03	3,167,190.52	35,483,734.17
Distribution (580-599)	9,195,883.07	778,955.81	946,026.65	9,476,199.47
Cust. Accounting (901-905)	4,655,166.55	341,606.20	287,139.05	4,286,915.55
Cust. Service (907-910)	5,450,370.64	162,391.16	2,266,552.25	7,326,954.75
Admin. & General (920-935)	10,867,235.88	782,453.54	876,436.32	9,750,830.21
Total O & M Expenses	123,862,744.43	11,202,019.48	12,967,508.81	119,330,154.89
Other Operating Expenses:				
Deprtn. & Amort. (403-407)	15,283,961.84	1,308,155.00	1,413,964.27	15,943,219.24
Taxes-Other Than Inc. (408)	6,435,130.39	605,947.38	603,224.70	7,166,677.86
Federal Income Taxes (409)	4,672,110.93	585,123.98	(1,125,648.02)	(1,180,388.21)
State Income Tax (409)	1,707,348.81	201,650.30	(882,799.80)	(1,096,467.99)
Def. Income Taxes (410, 411)	(3,692,668.40)	(690,163.08)	2,235,817.12	5,203,293.64
Total Other Operating Expenses	24,405,883.57	2,010,713.58	2,244,558.27	26,036,334.54
TOTAL OPERATING EXPENSES	148,268,628.00	13,212,733.06	15,212,067.08	145,366,489.43
NET UTILITY OPERATING INCOME	13,563,197.80	760,285.88	1,124,563.20	13,556,965.89
OTHER INCOME & DEDUCTIONS				
Other Income:				
Other (419, 421)	404,907.13	33,830.61	25,084.40	370,641.22
Other Income Deduc. (425, 426)	225,986.05	58,258.29	35,368.87	272,573.95
Taxes Other than Income Taxes				
Income Tax, Other Inc & Ded (409)	48,457.19	(6,615.75)	(2,785.34)	26,559.56
Net Other Income & Deductions	130,463.89	(17,811.93)	(7,499.13)	71,507.71
GROSS INCOME	13,693,661.69	742,473.95	1,117,064.07	13,628,473.60
Interest Charges (427-432)	6,083,865.12	487,827.87	485,708.65	5,495,091.82
NET INCOME	7,609,796.57	254,646.08	631,355.42	8,133,381.78

UNITIL ENERGY SYSTEMS, INC.
Balance Sheet-UES Rate Case
G_UES_BS_Rate_Case

Schedule 2
2/24/2021
December 31, 2020

	December 2019	January 2020	December 2020
ASSETS			
UTILITY PLANT			
Electric (101-106, 114)	$364,884,659.72	$365,881,123.15	$405,090,652.27
Const. Work in Progress (107)	15,945,622.37	16,941,969.02	5,132,122.53
Total Utility Plant	380,830,282.09	382,823,092.17	410,222,774.80
Less: Accum. Depr. & Amort (108-111, 115)	(131,447,315.33)	(132,328,294.03)	(137,912,641.04)
Net Utility Plant	249,382,966.76	250,494,798.14	272,310,133.76
OTHER PROPERTY & INVESTMENTS			
Nonutility Property (121)	50,606.49	50,606.49	50,606.49
Total Other Prop. & Invest.	50,606.49	50,606.49	50,606.49
CURRENT ASSETS			
Cash (131)	$92,042.68	($504,692.51)	$363,677.16
Other Special Deposits (134, 136)	1,450,587.56	1,194,368.24	2,243,895.03
Working Funds (135)	3,000.00	3,000.00	3,000.00
Accounts Receivable (142)	16,168,345.82	17,377,435.52	18,946,029.83
Other Accounts Receivable (143)	325,887.10	327,865.38	302,295.39
(Less) Accum. Prov. for Uncoll. Acct (144)	(161,878.34)	(50,798.34)	(556,372.26)
Accts Receivable-Assoc. Cos. (146)	4,575,451.35	0.00	6,113,319.66
Plant Material & Operating Supplies (154)	1,174,870.23	1,218,845.45	1,206,272.24
Stores Expense Undistributed (163)	189,428.38	200,590.57	201,951.60
Prepayments (165)	6,868,916.00	6,515,584.64	6,012,558.56
Accrued Revenues (173)	13,258,847.28	8,684,738.58	12,242,701.15
Miscellaneous Current and Accrued Assets (174)	67,464.45	67,464.45	146,490.54
Total Current Assets	44,012,962.51	35,034,401.98	47,225,818.90
DEFERRED DEBITS			
Unamortized Debt Expense (181)	1,180,809.49	1,169,151.14	1,254,800.71
Regulatory Assets (182)	39,976,170.79	27,493,967.09	43,973,873.05
Preliminary Survey Chgs (183)	114,328.01	130,234.09	351,614.46
Clearing Accounts (184)	648,177.11	1,070,881.37	624,028.38
Temporary Facilities (185)	779.06	(540.46)	4,863.38
Misc. Deferred Debits (186)	818,543.51	846,578.43	673,805.11
Deferred Taxes (190)	142,298.09	127,424.42	150,098.15
Total Deferred Debits	42,881,106.06	30,837,696.08	47,033,083.24
TOTAL ASSETS	$336,327,641.82	$316,417,502.69	$366,619,642.39

UNITIL ENERGY SYSTEMS, INC.
Balance Sheet-UES Rate Case
G_UES_BS_Rate_Case

Schedule 2
2/24/2021
December 31, 2020

	December 2019	January 2020	December 2020
LIABILITIES AND CAPITAL			
PROPRIETARY CAPITAL			
Common Stock Equity			
Common Stock of Subs, Par Value (201)	$2,442,426.00	$2,442,426.00	$2,442,426.00
Preferred Stock (204)	188,700.00	188,700.00	188,700.00
Premium on common stock (207)	1,005,875.00	1,005,875.00	1,005,875.00
Other Paid-In Capital (208, 211)	51,028,170.00	51,028,170.00	58,778,170.00
Capital Stock Expense (214)	(94,845.36)	(94,845.36)	(94,845.36)
Retained earnings (216)	42,949,034.13	41,490,038.71	44,220,301.91
Total Proprietary Capital	97,519,359.77	96,060,364.35	106,540,627.55
LONG TERM DEBT			
Bonds (221)	87,500,000.00	87,500,000.00	106,500,000.00
Total Long Term Debt	87,500,000.00	87,500,000.00	106,500,000.00
Capital Leases-Noncurrent	1,059,789.70	1,289,419.52	1,192,810.32
CURRENT LIABILITIES			
Accounts Payable (232)	19,800,942.61	16,704,791.83	18,174,447.34
Notes Payable (233)	13,065,032.41	15,981,464.93	8,176,367.77
Accts. Payable-Assoc. Co's (234)	9,541,172.55	9,376,629.68	10,603,841.16
Customer Deposits (235)	593,573.46	560,487.76	371,830.45
Taxes Accrued (236)	1,999,449.49	2,783,700.07	113,872.86
Interest Accrued (237)	887,325.50	1,014,450.57	1,019,683.22
Dividends Declared (238)	1,452,036.50	1,713,641.50	1,715,528.50
Tax Collections Payable (241)	5,727.12	0.00	16,637.68
Misc. Current Liabilities (242)	3,296,631.64	1,054,997.44	3,017,271.11
Capital Leases - Current (243)	383,170.79	443,934.32	489,212.64
Total Current Liabilities	51,025,062.07	49,634,098.10	43,698,692.73
DEFERRED CREDITS			
Cust Adv for Construction (252)	525,415.92	470,497.13	554,216.53
Other Deferred Credits (253)	59,484,810.74	36,802,449.74	65,121,368.99
Other Regulatory Liabilities (254)	22,752,203.12	22,752,203.12	22,752,203.12
Accum. Deferred Inc. Taxes - Other Prop. (282, 283)	35,909,355.14	35,952,616.79	40,133,815.65
Accum. Def. Income Taxes (282, 283)	(19,448,354.64)	(14,044,146.06)	(19,874,092.50)
Total Deferred Credits	99,223,430.28	81,933,620.72	108,687,511.79
TOTAL LIABILITIES AND CAPITAL	$336,327,641.82	$316,417,502.69	$366,619,642.39

(2) Annual reports to stockholders and statistical supplements, if any, for the most recent 5 years;

Response:

Unitil Energy Systems, Inc. does not make an annual report to stockholders.

(3) Federal income tax reconciliation for the test year.

Response:

Please refer to Schedule RevReq-3-21, Page 3 of 4 for the federal and state income tax reconciliation for the test year.

Unitil Energy Systems, Inc.
DE 21-030

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with PUC 1604.01(a), please provide:

(4) A detailed computation of New Hampshire and federal income tax factors on the increment of revenue needed to produce a given increment of net operating income;

Response:

Please refer to PUC 1604.01(a) - 04 Attachment 1 which is the computation of Gross-Up Factor for Revenue Requirement.

PUC 1604.01(a)(4)
Attachment 1

UNITIL ENERGY SYSTEMS, INC
COMPUTATION OF GROSS-UP FACTOR FOR REVENUE REQUIREMENT
12 MONTHS ENDED DECEMBER 31, 2020

LINE NO	DESCRIPTION	RATE	
1	Revenue		1.0000
2	State Income Tax	7.70%	0.0770
3	Subtotal taxable income - Federal		0.9230
4	Federal Income Tax	21.00%	0.1938
5	Net Operating Income		0.7292
6	Gross-up Factor (1/Line 5)		1.3714

Unitil Energy Systems, Inc.
DE 21-030

Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(5) A detailed list of charitable contributions charged in the test year showing done, the amount, and the amount charged according to the following guidelines:

a. If the utility's annual gross revenues are less than $100,000,000 all contributions of $50 and more shall be reported;
b. If the utility's annual gross revenues are $100,000,000 or more, all contributions of $2,500 and more shall be reported; and
c. The reporting threshold for a particular charity shall be on a cumulative basis, indicating the number of items comprising the total amount of contribution.

Response:

There were no charitable contributions of $2,500 or more above the line during the test year.

Unitil Energy Systems, Inc.
DE 21-030
Supplementary Filing Requirements
Pursuant to Puc 1604.01(a)

In accordance with Puc 1604.01(a), please provide:

(6) A list of advertising charged in the test year above the line showing expenditure by media, subject matter and account charged according to the following guidelines:

a. If the utility's annual gross revenues are less than $100,000,000 all expenditures of $50 and more shall be reported; and
b. If the utility's annual gross revenues are $100,000,000 or more, all expenditures of $2,500 and more shall be reported;

Response:

There were no advertising charges of $2,500 or more above the line during the test year.

(7) The utility's most recent cost of service study.

Response:

The Company cost of service study is attached to the Testimony of Christopher Goulding and Daniel Nawazelski.

(8) The utility's most recent construction budget.

Response:

See PUC 1604.01(a) – 8 Attachments 1 and 2 for the utility's most recent construction budget.

Capital Budget System • Report • Budget Item Requests

Printed: 2/15/2021 2:26:48 PM

Capital Budget 2021 UES Capital								
Description	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions	Retirements	Salvage
Blankets:Electric	3,109,796	4,653,226	515,052	4,138,174	171,114	3,967,060	45,280	5,328
Communications:Electric	187,500	190,500	0	190,500	0	190,500	0	0
Distribution:Electric	3,556,737	5,321,989	186,442	5,135,548	90,366	5,045,182	7,168	868
Tools, Shop, Garage:Electric	152,300	152,300	0	152,300	0	152,300	0	0
Office:Electric	3,000	3,000	0	3,000	0	3,000	0	0
Substation:Electric	746,858	1,093,975	0	1,093,975	0	1,093,975	300	0
Transportation:Electric	3	3	0	3	0	3	0	0
Electric Totals:	7,756,195	11,414,993	701,493	10,713,500	261,480	10,452,020	52,748	6,196
Gas Totals:	0	0	0	0	0	0	0	0
Hotwater Totals:	0	0	0	0	0	0	0	0
Tools, Shop, Garage:General	0	0	0	0	0	0	0	0
Laboratory:General	7,000	7,000	0	7,000	0	7,000	0	0
Structures:General	58,000	58,000	0	58,000	0	58,000	0	0
General/Common Totals:	65,000	65,000	0	65,000	0	65,000	0	0
Totals:	**7,821,195**	**11,479,993**	**701,493**	**10,778,500**	**261,480**	**10,517,020**	**52,748**	**6,196**

Capital Budget System • Report • Budget Item Requests

Printed: 2/15/2021 2:27:09 PM

Capital Budget 2021 UES Capital

Status	Priority	Budget Number	Description **Blankets:Electric**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	1	BABC21	T&D Improvements	866,422	1,296,438	129,644	1,166,794	64,416	1,102,378
A	1	BACC21	T&D Improvements, Carryover	19,573	29,287	2,929	26,359	3,206	23,153
A	1	BBBC21	New Customer Additions	287,713	430,509	28,771	401,738	19,386	382,352
A	1	BBCC21	New Customer Additions, Carryover	30,160	45,128	3,016	42,112	5,190	36,923
A	1	BCBC21	Outdoor Lighting	72,747	108,853	5,443	103,410	6,411	96,999
A	1	BCCC21	Outdoor Lighting, Carryover	2,972	4,446	222	4,224	611	3,614
A	1	BDBC21	Emergency & Storm Restoration	443,454	663,545	0	663,545	27,476	636,069
A	1	BDCC21	Emergency & Storm Restoration, Carryover	7,556	11,306	0	11,306	611	10,695
A	1	BEBC21	Billable Work	357,598	535,078	321,047	214,031	42,588	171,443
A	1	BECC21	Billable Work, Carryover	14,244	21,313	12,788	8,525	1,221	7,304
A	1	BFBC21	Transformers Company/Conversions	59,220	88,611	0	88,611	0	88,611
A	1	BFCC21	Transformers Company/Conversions, Carryover	0	0	0	0	0	0
A	1	BGBC21	Transformer Customer Requirements	505,566	756,484	10,111	746,373	0	746,373
A	1	BGCC21	Transformer Customer Requirements, Carryover	54,035	80,853	1,081	79,772	0	79,772
A	1	BHBC21	Meter Blanket Company Requirements	117,758	176,203	0	176,203	0	176,203
A	1	BIBC21	Meter Blanket Customer Requirements	270,780	405,171	0	405,171	0	405,171
			Totals:	3,109,796	4,653,226	515,052	4,138,174	171,114	3,967,060

Capital Budget System • Report • Budget Item Requests

Printed: 2/15/2021 2:27:21 PM

Capital Budget 2021 UES Capital

Status	Priority	Budget Number	Description **Communications:Electric**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	2	ECEC01	Two Way Radio Replacements	2,500	2,500	0	2,500	0	2,500
A	2	EECC01	Radio Upgrade Project	175,000	175,000	0	175,000	0	175,000
A	1	EECC02	Upgrade TS2 to PLX Infrastructure Carryover	10,000	13,000	0	13,000	0	13,000
			Totals:	187,500	190,500	0	190,500	0	190,500

Capital Budget System • Report • Budget Item Requests

Printed: 2/15/2021 2:27:34 PM

Capital Budget 2021 UES Capital

Status	Priority	Budget Number	Description **Distribution:Electric**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	1	DABC20	Overhead Line Extensions	33,146	49,597	19,888	29,709	4,885	24,824
A	1	DACC20	Overhead Line Extensions - Carryover	5,961	8,920	3,577	5,343	1,069	4,275
A	1	DBBC20	Underground Line Extensions	226,548	338,986	135,929	203,057	0	203,057
A	1	DBCC20	Underground Line Extensions, Carryover	39,907	59,713	23,944	35,769	0	35,769
A	1	DCBC20	Street Light Projects	4,482	6,706	2,683	4,024	763	3,261
A	1	DCCC20	Street Light Projects - Carryover	705	1,055	422	633	0	633
A	2	DDBC20	Telephone Company Requests	8,932	13,365	0	13,365	1,526	11,838
A	2	DDCC20	Telephone Company Request - Carryover	0	0	0	0	0	0
A	2	DEBC20	Highway Projects	52,381	78,378	0	78,378	3,969	74,409
A	2	DECC20	Highway Projects, Carryover	19,611	29,344	0	29,344	1,832	27,513
A	2	DPBC01	Distribution Pole Replacement	457,926	685,200	0	685,200	59,837	625,364
A	3	DPBC02	Porcelain Cutout Replacements	149,040	223,010	0	223,010	15,264	207,746
A	1	DPBC03	37 Line - Reconductor Penacook to Maccoy St Tap	696,126	1,041,622	0	1,041,622	0	1,041,622
A	3	DPBC04	Replace Direct Buried URD Cable Rocky Point Dr, Bow	58,517	87,560	0	87,560	0	87,560
A	3	DPBC05	Perform Cable Injection Fairfield St. Concord	113,438	169,738	0	169,738	0	169,738
A	3	DPBC06	Cable Injection - 129 Fisherville Rd, Concord	50,276	75,229	0	75,229	0	75,229
A	2	DPBC07	38 Line Spacer Reconductoring	166,059	248,476	0	248,476	0	248,476
A	3	DPBC08	Perform Cable Injection on Cambridge Dr. Canterbury	18,983	28,404	0	28,404	0	28,404
A	3	DPBC09	Arc Hazard Mitigation - 374X1 Tap	75,222	112,556	0	112,556	0	112,556
A	2	DPBC10	Replace 33 Line Structure	107,263	160,499	0	160,499	0	160,499
A	2	DPBC11	36 Line River Crossing Replacement	246,963	369,534	0	369,534	0	369,534
A	2	DPBC12	38 Line River Crossing Replacement	247,083	369,713	0	369,713	0	369,713
A	1	DPCC01	Extend Brown Hill Rd, Bow - 22W3	236,872	354,435	0	354,435	1,221	353,214
A	1	DPCC02	374 Line Rebuild with 15kV Underbuild	96,284	144,071	0	144,071	0	144,071
A	2	DPCC03	Manhole improvements MH 6	136,963	204,939	0	204,939	0	204,939
A	3	DRBC00	Reliability Projects	308,050	460,939	0	460,939	0	460,939
			Totals:	3,556,737	5,321,989	186,442	5,135,548	90,366	5,045,182

000019

Capital Budget System • Report • Budget Item Requests

Printed: 2/15/2021 2:27:46 PM

Capital Budget 2021 UES Capital

Status	Priority	Budget Number	Description **Tools, Shop, Garage:Electric**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	2	EAEC01	Purchase and Replace Rubber Goods	6,000	6,000	0	6,000	0	6,000
A	2	EAEC02	Purchase and Replace Hot Line Tools	4,000	4,000	0	4,000	0	4,000
A	2	EAEC03	Tools, Shop & Garage - Normal Additions and Replacements	14,500	14,500	0	14,500	0	14,500
A	2	EAEC04	Normal additions & replacement - tools & equipment Metering	7,000	7,000	0	7,000	0	7,000
A	2	EAEC05	Normal Additions and Replacements - Tools and Equipment - Substation	12,000	12,000	0	12,000	0	12,000
A	3	EAEC07	Purchase OMICRON ARCO Recloser Test Set	31,800	31,800	0	31,800	0	31,800
A	3	EAEC08	Purchase Omicron Power Factor Test Set	77,000	77,000	0	77,000	0	77,000
			Totals:	152,300	152,300	0	152,300	0	152,300

Capital Budget System • Report • Budget Item Requests

Printed: 2/15/2021 2:28:10 PM

Capital Budget 2021 UES Capital

Status	Priority	Budget Number	Description **Office:Electric**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	3	EDEC01	Office Furn & Equip - Normal Replacement & Additions	3,000	3,000	0	3,000	0	3,000
			Totals:	3,000	3,000	0	3,000	0	3,000

Capital Budget System • Report • Budget Item Requests

Printed: 2/15/2021 2:28:35 PM

Capital Budget 2021 UES Capital

Status	Priority	Budget Number	Description **Substation:Electric**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	3	SPBC01	Garvins - Replace SCADA RTU	30,445	45,555	0	45,555	0	45,555
A	3	SPBC02	Terrill Park - Replace SCADA RTU and Upgrade Equipment	202,165	290,233	0	290,233	0	290,233
A	2	SPBC03	Bridge Street Substation Upgrades	0	0	0	0	0	0
A	3	SPBC04	Langdon Avenue - Replace SCADA RTU	32,945	49,295	0	49,295	0	49,295
A	2	SPBC08	Replace Fence Sections at Langdon, Boscawen and Penacook S/S	45,889	68,664	0	68,664	0	68,664
A	2	SPBC09	Iron Works 22W1 Control Replacement	22,829	34,159	0	34,159	0	34,159
A	1	SPBC10	Replace 13W2 Circuit Position Regulators	184,209	264,346	0	264,346	0	264,346
A	1	SPCC01	Bow Junction - Transformer High-Side Protection	77,741	116,325	0	116,325	0	116,325
A	3	SPCC02	West Concord - Replace RTU and Upgrade Equipment	150,635	225,397	0	225,397	0	225,397
			Totals:	746,858	1,093,975	0	1,093,975	0	1,093,975

Capital Budget System • Report • Budget Item Requests

Printed: 2/15/2021 2:28:47 PM

Capital Budget 2021 UES Capital

Status	Priority	Budget Number	Description **Transportation:Electric**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	2	FEBC01	Replace pickup truck #48 - Substation	1	1	0	1	0	1
A	2	FEBC02	Replace pickup truck #54 - Standby	1	1	0	1	0	1
A	2	FEBC03	Replace Electric fork lift-#3	1	1	0	1	0	1
			Totals:	3	3	0	3	0	3

Capital Budget System • Report • Budget Item Requests

Printed: 2/15/2021 2:27:58 PM

Capital Budget 2021 UES Capital

Status	Priority	Budget Number	Description **Laboratory:General**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	2	EBBC01	Lab Equipment - Normal Additions and Replacements	7,000	7,000	0	7,000	0	7,000
			Totals:	7,000	7,000	0	7,000	0	7,000

Capital Budget System • Report • Budget Item Requests

Printed: 2/15/2021 2:28:25 PM

Capital Budget 2021 UES Capital

Status	Priority	Budget Number	Description **Structures:General**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	3	GPBC01	Normal Improvements to Capital Facility	18,000	18,000	0	18,000	0	18,000
A	3	GPBC03	Electric Vehicle Charging Stations – Capital	40,000	40,000	0	40,000	0	40,000
			Totals:	58,000	58,000	0	58,000	0	58,000

Capital Budget System • Report • Budget Item Requests

Printed: 2/15/2021 2:29:08 PM

Capital Budget 2021 UES Seacoast

Description	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions	Retirements	Salvage
Blankets:Electric	4,284,856	6,411,482	529,404	5,882,077	298,878	5,583,199	37,015	5,613
Communications:Electric	2,500	2,500	0	2,500	0	2,500	0	0
Distribution:Electric	6,903,262	10,328,938	303,674	10,025,264	63,195	9,962,070	25,884	3,336
Tools, Shop, Garage:Electric	62,200	62,200	0	62,200	0	62,200	1,300	0
Office:Electric	1,000	1,000	0	1,000	0	1,000	250	0
Substation:Electric	412,726	605,788	0	605,788	0	605,788	5,000	0
Transportation:Electric	4	4	0	4	0	4	0	0
Electric Totals:	11,666,548	17,411,912	833,078	16,578,834	362,073	16,216,761	69,449	8,949
Gas Totals:	0	0	0	0	0	0	0	0
Hotwater Totals:	0	0	0	0	0	0	0	0
Laboratory:General	7,000	7,000	0	7,000	0	7,000	0	0
Structures:General	542,000	542,000	0	542,000	0	542,000	1,735,000	800,000
General/Common Totals:	549,000	549,000	0	549,000	0	549,000	1,735,000	800,000
Totals:	**12,215,548**	**17,960,912**	**833,078**	**17,127,834**	**362,073**	**16,765,761**	**1,804,449**	**808,949**

Capital Budget System • Report • Budget Item Requests

Printed: 2/15/2021 2:29:21 PM

Capital Budget 2021 UES Seacoast

Status	Priority	Budget Number	Description **Blankets:Electric**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	1	BABE21	T&D Improvements	1,118,521	1,673,657	66,946	1,606,711	76,322	1,530,389
A	1	BACE21	T&D Improvements, Carryover	52,265	78,204	0	78,204	6,106	72,098
A	1	BBBE21	New Customer Additions	367,003	549,151	54,915	494,236	45,793	448,443
A	1	BBCE21	New Customer Additions, Carryover	12,758	19,089	0	19,089	0	19,089
A	1	BCBE21	Outdoor Lighting	100,961	151,069	1,511	149,558	15,264	134,293
A	1	BCCE21	Outdoor Lighting, Carryover	7,030	10,520	0	10,520	1,221	9,298
A	1	BDBE21	Emergency & Storm Restoration	432,159	646,645	0	646,645	91,587	555,058
A	1	BDCE21	Emergency & Storm Restoration, Carryover	11,848	17,728	0	17,728	1,526	16,201
A	1	BEBE21	Billable Work	552,089	826,097	371,744	454,353	61,058	393,295
A	1	BECE21	Billable Work, Carryover	0	0	0	0	0	0
A	1	BFBE21	Transformer Company/Conversion	44,651	66,811	0	66,811	0	66,811
A	1	BFCE21	Transformers Company/Conversion Carryover	130,000	194,521	0	194,521	0	194,521
A	1	BGBE21	Transformers Customer Requirements	763,853	1,142,962	34,289	1,108,673	0	1,108,673
A	1	BGCE21	Transformer Customer Requirements, Carryover	100,000	149,631	0	149,631	0	149,631
A	1	BHBE21	Meter Blanket Company Requirements	236,489	353,861	0	353,861	0	353,861
A	1	BIBE21	Meter Blanket Customer Requirements	355,231	531,536	0	531,536	0	531,536
			Totals:	4,284,856	6,411,482	529,404	5,882,077	298,878	5,583,199

Capital Budget System • Report • Budget Item Requests

Printed: 2/15/2021 2:29:32 PM

Capital Budget 2021 UES Seacoast										
Status	Priority	Budget Number	Description **Communications:Electric**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	2	ECEE01	Two Way Radio Replacements	2,500	2,500	0	2,500	0	2,500
			Totals:	2,500	2,500	0	2,500	0	2,500

Capital Budget System • Report • Budget Item Requests

Printed: 2/15/2021 2:29:43 PM

Capital Budget 2021 UES Seacoast

Status	Priority	Budget Number	Description **Distribution:Electric**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	1	DABE00	Overhead Line Extensions - New Projects	62,686	93,798	37,611	56,186	3,053	53,133
A	1	DACE00	Overhead Line Extensions, Carryover	15,890	23,777	0	23,777	1,832	21,945
A	1	DBBE00	Underground Line Extensions - New Projects	443,437	663,521	266,062	397,458	0	397,458
A	1	DBCE00	Underground Line Extensions, Carryovers	220,967	330,636	0	330,636	0	330,636
A	2	DCBE00	Street Light Projects	0	0	0	0	0	0
A	2	DCCE00	Street Light Projects, Carryover	0	0	0	0	0	0
A	2	DEBE00	Highway Projects	140,921	210,862	0	210,862	7,632	203,230
A	2	DECE00	Highway Projects, Carryover	0	0	0	0	0	0
A	2	DPBE01	Distribution Pole Replacements	578,737	865,971	0	865,971	27,476	838,495
A	2	DPBE02	Reconstruct the 3348/50 Sub-Transmission Lines	3,500,000	5,237,092	0	5,237,092	0	5,237,092
A	1	DPBE04	23X1 – Install Stepdowns and Add Primary on New Amesbury Rd/Highland Rd, South Hampton	64,668	96,763	0	96,763	611	96,153
A	1	DPBE05	15X1 – Upgrade Stepdown Transformer, Pine St, Seabrook	6,690	10,010	0	10,010	1,221	8,789
A	3	DPBE07	Circuit 6W1 - Convert Jewell St. South Hampton to 8 kV	261,869	391,838	0	391,838	3,053	388,786
A	3	DPBE08	Arc Hazard Mitigation - 27X1 - Trundlebed Road, Kensington	181,504	271,587	0	271,587	0	271,587
A	3	DPBE09	Arc Hazard Mitigation - 56X1 - Newton Junction Road, Kingston	181,504	271,587	0	271,587	0	271,587
A	3	DPBE10	Arc Hazard Mitigation - 46X1 - Winnacunnet Road Tap, Hampton	181,504	271,587	0	271,587	0	271,587
A	3	DPBE11	Arc Hazard Mitigation - 5X3 - Stepdowns, Witch Lane, Plaistow	75,222	112,556	0	112,556	0	112,556
A	3	DPBE12	Porcelain Cutout Replacements, Various Locations	153,449	229,607	0	229,607	15,264	214,343
A	2	DPCE01	Distribution Pole Replacements	64,550	96,587	0	96,587	0	96,587
A	2	DPCE02	Circuit 58X1, Convert Main St, Plaistow	222,234	332,532	0	332,532	3,053	329,479
A	2	DPCE03	Town of Exeter, Sidewalk Installations, Relocate Poles	38,356	57,393	0	57,393	0	57,393
A	2	DPCE04	18X1 R2 Recloser Replacement, Timberswamp Rd, Hampton	30,000	44,889	0	44,889	0	44,889
A	3	DRBE00	Reliability Projects	227,327	339,657	0	339,657	0	339,657
A	3	DRCE01	Circuit 43X1 – Install Reclosers and Implement Distribution Automation	233,916	350,011	0	350,011	0	350,011
A	3	DRCE02	Circuit 19X2 - Distribution Automation	17,829	26,678	0	26,678	0	26,678

Scheme with Portsmouth Ave							
	Totals:	6,903,262	10,328,938	303,674	10,025,264	63,195	9,962,070

Capital Budget System • Report • Budget Item Requests

Printed: 2/15/2021 2:29:56 PM

Capital Budget 2021 UES Seacoast

Status	Priority	Budget Number	Description **Tools, Shop, Garage:Electric**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	2	EAEE01	Tools, Shop & Garage – Normal Additions and Replacements	14,500	14,500	0	14,500	0	14,500
A	2	EAEE02	Purchase and Replace Rubber Goods	6,000	6,000	0	6,000	0	6,000
A	2	EAEE03	Purchase and Replace Hot Line Tools	4,500	4,500	0	4,500	0	4,500
A	2	EAEE04	Normal additions & replacement - tools & equipment Meter and Services	7,000	7,000	0	7,000	0	7,000
A	2	EAEE05	Normal Additions and Replacements- Tools and Equipment Substation	12,000	12,000	0	12,000	0	12,000
A	3	EAEE06	Purchase Power Back	3,200	3,200	0	3,200	0	3,200
A	2	EAEE69	Purchase Toolng for New Bucket Truck	15,000	15,000	0	15,000	0	15,000
			Totals:	62,200	62,200	0	62,200	0	62,200

Capital Budget System • Report • Budget Item Requests

Printed: 2/15/2021 2:30:18 PM

Capital Budget 2021 UES Seacoast

Status	Priority	Budget Number	Description **Office:Electric**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	3	EDEE01	Office Furniture & Equipment – Normal Additions & Replacements	1,000	1,000	0	1,000	0	1,000
			Totals:	1,000	1,000	0	1,000	0	1,000

Capital Budget System • Report • Budget Item Requests

Printed: 2/15/2021 2:30:42 PM

Capital Budget 2021 UES Seacoast										
Status	Priority	Budget Number	Description **Substation:Electric**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	3	SPBE01	Replace Fence at Gilman Lane Substation	55,889	83,628	0	83,628	0	83,628
A	2	SPBE02	High Street Substation, Hampton - Replace 17W1 & 17W2 Relays	34,815	52,094	0	52,094	0	52,094
A	3	SPBE04	Guinea Substation, Hampton - Install Time Keeping System	9,300	13,916	0	13,916	0	13,916
A	2	SPBE05	Munt Hill Substation - Replace 28X1 Recloser	42,829	64,086	0	64,086	0	64,086
A	2	SPBE07	Rebuild Mill Lane Tap	180,000	257,557	0	257,557	0	257,557
A	2	SPBE08	Substation Stone Installation, Various Locations	32,945	49,295	0	49,295	0	49,295
A	3	SPCE01	Replace Remaining Multi-Drop Telephone Landline Services	40,089	59,986	0	59,986	0	59,986
A	2	SPCE02	Westville Substation, Plaistow - Replace SCADA RTU	16,859	25,226	0	25,226	0	25,226
			Totals:	412,726	605,788	0	605,788	0	605,788

Capital Budget System • Report • Budget Item Requests

Printed: 2/15/2021 2:30:54 PM

Capital Budget 2021 UES Seacoast

Status	Priority	Budget Number	Description **Transportation:Electric**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	2	FEBE01	Replace Pick up Truck #26 - Metering	1	1	0	1	0	1
A	2	FEBE02	Replace Pick Up Truck #30	1	1	0	1	0	1
A	2	FEBE03	Replace Pick Up Truck #24	1	1	0	1	0	1
A	2	FEBE04	Purchase New Bucket Truck	1	1	0	1	0	1
			Totals:	4	4	0	4	0	4

Capital Budget System • Report • Budget Item Requests

Printed: 2/15/2021 2:30:07 PM

Capital Budget 2021 UES Seacoast

Status	Priority	Budget Number	Description **Laboratory:General**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	2	EBBE01	Lab Equipment - Normal Additions and Replacements	7,000	7,000	0	7,000	0	7,000
			Totals:	7,000	7,000	0	7,000	0	7,000

Capital Budget System • Report • Budget Item Requests

Printed: 2/15/2021 2:30:32 PM

Capital Budget 2021 UES Seacoast

Status	Priority	Budget Number	Description **Structures:General**	Total Project Cost w/o Constr OH	Total Project Cost w/Constr OH	Total Estimated Customer Contribution	Total Expenditure	Cost of Removal	Additions
A	3	GPBE01	Normal Improvements to Seacoast DOC Facilities	7,500	7,500	0	7,500	0	7,500
A	3	GPBE02	Plaistow Garage Improvements	27,000	27,000	0	27,000	0	27,000
A	3	GPCE01	Construct New NH Seacoast Region Facility, Carryover	500,000	500,000	0	500,000	0	500,000
A	3	GPCE02	Sale of Kensington DOC Facility, Carryover	7,500	7,500	0	7,500	0	7,500
			Totals:	542,000	542,000	0	542,000	0	542,000

(9) The utility's chart of accounts, if different from the uniform system of accounts established by the commission as part of PUC 300, PUC 400, PUC 500, PUC 600 and PUC 700;

Response:

The utility's chart of accounts is not different from the uniform system of accounts established by the commission as part of PUC 300, PUC 400, PUC 500, PUC 600 and PUC 700.

Please see PUC 1604.01(a) – 09 Attachment 1 for the Chart of Accounts.

.

Account Code	Description	Type	Status
102000001010000	ELEC PLANT IN SERVICE	Assets	Active
102000001010200	RIGHT OF USE ASSETS	Assets	Active
102000001010201	CONTRA RIGHT OF USE ASSETS	Assets	Active
102000001010300	ELEC PLANT IN SERVICE CIS	Assets	Active
102000001019000	ELEC PLANT IN SERVICE (GA CONTRA)	Assets	Active
102000001060000	COMP CONST NOT CLASS	Assets	Active
102000001070000	CONST WORK IN PROGRESS	Assets	Active
102000001070102	RWIP ELEC SALVAGE	Assets	Active
102000001070103	RWIP ELEC COST OF REMOVAL	Assets	Active
102000001079000	CONSTRUCTION WORK IN PROGRESS GA	Assets	Active
102000001080100	ACCUM DEPR GENERAL PLANT	Assets	Active
102000001080105	ACCUM DEPR RESERVE - ELEC	Assets	Active
102000001080400	ACCUMULATED DEPRECIATION - COR	Assets	Active
102000001089000	ACCUM DEPR- GENERAL PLANT (GA CONTRA)	Assets	Active
102000001110500	ACCUM AMORT	Assets	Active
102000001110700	ACCUM AMORT - CIS	Assets	Active
102000001310000	CASH - REMITTANCE - CITIZENS	Assets	Active
102000001310001	CASH - SUSPENSE	Assets	Active
102000001311000	CASH - GENERAL FUNDS - BANK OF AMERICA	Assets	Active
102000001312000	CASH - CONTROL DISBURSEMENT - FLEET	Assets	Active
102000001314000	CASH - CASHPOOL	Assets	Active
102000001340000	OTHER SPECIAL DEPOSITS	Assets	Active
102000001350000	CASH - WORKING FUNDS	Assets	Active
102000001360000	TEMP CASH INVESTMENTS	Assets	Active
102000001420100	A/R ELECTRIC	Assets	Active
102000001420101	A/R SUSPENSE	Assets	Active
102000001420200	A/R MERCHANDISING	Assets	Active
102000001420300	A/R CONTRACT WORK	Assets	Active
102000001420302	MISC A/R ACCRUALS	Assets	Active
102000001420402	A/R MISC - URC	Assets	Active
102000001420500	A/R CASH SALES CLEAR	Assets	Active
102000001420601	A/R - STRATHAM ST LIGHT LEDS	Assets	Active
102000001420701	A/R - SUSPENSE - PP	Assets	Active
102000001420800	AR PROTECTED ACCTS > 360 DAYS	Assets	Active
102000001430000	AR OTHER	Assets	Active
102000001430105	A/R NEEWBF RETIREE PREM	Assets	Active
102000001430300	A/R EMPLOYEE P.C. PURCHASES	Assets	Active
102000001430303	A/R DRUG SUBSIDY	Assets	Active
102000001438900	MISC A/R - INSURANCE RECOVERY	Assets	Active
102000001440000	AFDA - BEG BAL - DIST	Assets	Active
102000001440001	ALLOW FOR DOUBTFUL ACCTS - DISTR	Assets	Active
102000001440003	AFDA - SUPPLY - BEG BAL (NON DIST)	Assets	Active
102000001440027	ALLOW FOR DOUBTFUL ACCTS-NON-DIST	Assets	Active
102000001441300	AFDA - UNBILLED REVENUE RECEIVABLE	Assets	Active
102000001441600	ALLOWANCE - SUNDRY - MAINT TREE TRIMMING	Assets	Active
102000001460001	A/R ASSOC CO-SUSPENSE	Assets	Active
102000001460100	A/R ASSOC CO-ACCRUALS	Assets	Active

102000001460102	A/R ASSOC CO - VENDOR BILLBACK DEBIT BALANCE RECLASS ONLY	Assets	Active
102000001460112	A/R ASSOC COS - USC	Assets	Active
102000001460113	A/R ASSOC COS - UPC	Assets	Active
102000001460115	A/R ASSOC COS - UC	Assets	Active
102000001460121	A/R ASSOC COS - FEDCO	Assets	Active
102000001460124	A/R ASSOC COS - URI	Assets	Active
102000001460133	A/R ASSOC COS - GSG	Assets	Active
102000001650100	PREPAID PROPERTY INSURANCE	Assets	Active
102000001650101	PREPAID INJ & DAMAGES INS	Assets	Active
102000001650104	PREPAID WORKERS COMP. INSUR	Assets	Active
102000001650108	MISCELLANEOUS PREPAIDS	Assets	Active
102000001650202	PREPAID PUC ASSESSMENT	Assets	Active
102000001650401	FASB 87 - PREPAID PENSION	Assets	Active
102000001651100	PREPAID PROPERTY TAX	Assets	Active
102000001651200	PREPAID POSTAGE	Assets	Active
102000001651400	PREPAID REVOLVER	Assets	Active
102000001651500	PREPAID DUES & SUBSCRIPTIONS	Assets	Active
102000001651600	PREPAID HEALTH CLAIMS	Assets	Active
102000001652500	PREPAID LINE MAINTENANCE	Assets	Active
102000001710000	INT & DIVIDENDS RECEIVABLE	Assets	Active
102000001730000	ACCRUED ELECTRIC REVENUE	Assets	Active
102000001730010	Accrd Revenue - Elec Rate Case Costs - Short Term	Assets	Active
102000001731000	ACCRUED REVENUE - MAJOR STORM RESERVE	Assets	Active
102000001731100	ACCRUED REVENUE - VMP	Assets	Active
102000001731301	ACCRUED REVENUE-SYS BEN RES	Assets	Active
102000001731302	ACCRUED REVENUE-SYS BEN RES LOW INC	Assets	Active
102000001731303	ACCRUED REVENUE-SYS BEN C&I	Assets	Active
102000001731500	UNBILLED REVENUE - LI-EAP	Assets	Active
102000001732200	UNBILLED REVENUE - BASE	Assets	Active
102000001734200	CUR PORTION PUCHASED POWER CONTRACTS	Assets	Active
102000001734400	RPS - CURRENT PORTION	Assets	Active
102000001739000	ACCRUED REVENUE - CREDIT BALANCE RECLASS	Assets	Active
102000001739001	ACCRUED REVENUE - YEAREND FT AP ACCRUAL	Assets	Active
102000001740000	MISC CURRENT & ACCRUED ASSETS	Assets	Active
102000001740500	VACATION ACCRUAL	Assets	Active
102000001810000	UNAMORTIZED DEBT EXPENSE	Assets	Active
102000001810100	UNAMORTIZED DEBT EXPENSE - WITHIN 1 YEAR	Assets	Active
102000001820027	REG ASSET - NON-DIST BAD DEBT	Assets	Active
102000001820300	REG ASSET - SFAS 109 FED	Assets	Active
102000001820307	REG ASSET - RATE CASE COSTS	Assets	Active
102000001820409	REGULATORY ASSET - PBOP FAS 158	Assets	Active
102000001820410	REGULATORY ASSET - PENSION FAS 158	Assets	Active
102000001820411	REG ASSET - SERP	Assets	Active
102000001820419	REGULATORY ASSET - OTHER PBOP	Assets	Active
102000001820420	REGULATORY ASSET - OTHER PENSION	Assets	Active
102000001820421	REGULATORY ASSET - OTHER SERP	Assets	Active
102000001820700	REG ASSET - DER INVESTMENT	Assets	Active
102000001820800	REG ASSET - AR PROT ACCTS	Assets	Active
102000001821000	REG ASSET - MAJOR STORM RESERVE LONG TERM	Assets	Active

102000001821200	REG ASSET - TOU - CONSULTANT COSTS	Assets	Active
102000001821400	REG ASSET - DEFERRED PANDEMIC COSTS	Assets	Active
102000001821500	REG ASSET - DEFERRED PROPERTY TAXES	Assets	Active
102000001823601	REG ASSET - RPS - TYPE 1	Assets	Active
102000001828601	REG ASSET - HURRICANE IRENE	Assets	Active
102000001840001	ENG & OPER OVERHEADS-UES	Assets	Active
102000001840002	GENERAL OVERHEADS-UES	Assets	Active
102000001840300	SMALL TOOLS	Assets	Active
102000001840800	CASH DISCOUNTS TAKEN	Assets	Active
102000001860014	PREPAID REVOLVER - LT PORTION	Assets	Active
102000001860200	PLANT AND M&S ACCRUALS	Assets	Active
102000001860383	GENERATOR INTERCONNECTIONS STUDIES	Assets	Active
102000001861000	PROPERTY TAX ABATEMENT REC - LT	Assets	Active
102000001862702	CIS REPLACEMENT	Assets	Active
102000001863300	UES MERGER COSTS	Assets	Active
102000001863800	OTHER DEFERRED CHARGES	Assets	Active
102000001864000	DEFERRED CHARGES - STORM COSTS	Assets	Active
102000001869810	UES - STORM PREP	Assets	Active
102000001869820	FGE - STORM PREP	Assets	Active
102000001869910	UES - STORM EVENT	Assets	Active
102000001869920	FGE - STORM EVENT	Assets	Active
102000001900130	DEF FIT - CIAC	Assets	Active
102000001900199	DEF FIT - DEBIT BALANCE RECLASS	Assets	Active
102000001900230	DEF SIT - CIAC	Assets	Active
102000001900299	DEF SIT - DEBIT BALANCE RECLASS	Assets	Active
102000002010000	CAPITAL STOCK COMMON	Equity	Active
102000002040200	CAPITAL STOCK PREF 6%	Equity	Active
102000002070000	PREM ON CAPITAL STOCK	Equity	Active
102000002100000	CAP STOCK REACQUIRED	Equity	Active
102000002110000	MISC PAID IN CAPITAL	Equity	Active
102000002140101	CAPITAL STOCK EXP 1926	Equity	Active
102000002140102	CAPITAL STOCK EXP 1948	Equity	Active
102000002140103	CAPITAL STOCK EXP 1950	Equity	Active
102000002140104	CAPITAL STOCK EXP 1971	Equity	Active
102000002140105	CAPITAL STOCK EXP 1973	Equity	Active
102000002140106	CAPITAL STOCK EXP 1974	Equity	Active
102000002140107	CAPITAL STOCK EXP 1975	Equity	Active
102000002160000	RETAINED EARNINGS	Equity	Active
102000002210000	LT DEBT DUE WITHIN 1 YR TRANSF	Liability	Active
102000002210100	LT DEBT DUE WITHIN 1 YR	Liability	Active
102000002210300	1ST MORT. BONDS SER D	Liability	Active
102000002210800	1ST MORT. BONDS - 8.49% - I	Liability	Active
102000002210900	1ST MORT. BONDS - 6.96% - J	Liability	Active
102000002211000	1ST MORT. BONDS - 8.00% - K	Liability	Active
102000002211100	1ST MORT. BONDS - 6.96% - M	Liability	Active
102000002211200	1ST MORT. BONDS - 8.00% - N	Liability	Active
102000002211300	1ST MORT. BONDS - 8.49% - L	Liability	Active
102000002211400	1ST MORT. BONDS - 6.32% - O	Liability	Active
102000002211500	1ST MORT. BONDS - 5.24% - P	Liability	Active

102000002211600	1ST MORT. BONDS - 4.18% - Q	Liability	Active
102000002211700	1ST MORT. BONDS - 20 YR - 3.58% - R	Liability	Active
102000002270100	OPER LEASE OBLIG - NONCURRENT	Liability	Active
102000002310000	NOTES PAYABLE	Liability	Active
102000002320100	ACCTS PAYABLE VOUCHERS	Liability	Active
102000002320101	ACCOUNTS PAYABLE - ACCRUAL	Liability	Active
102000002320140	A/P CUR PORT PURCH POWER CONTRACTS	Liability	Active
102000002320144	A/P RPS - CURRENT PORTION	Liability	Active
102000002320200	ACCTS PAYABLE PAYROLL	Liability	Active
102000002320201	ACCRUED PAYROLL	Liability	Active
102000002320224	A/P-CUR PORT SINKING FUND COMMITMENTS	Liability	Active
102000002320305	A/P THRIFT PLAN/401(k) PLAN	Liability	Active
102000002320306	A/P 401K LOAN PROV	Liability	Active
102000002320307	A/P UNION DUES	Liability	Active
102000002320308	A/P WAGE ASSIGNMENT	Liability	Active
102000002320310	A/P UNITED WAY	Liability	Active
102000002320311	A/P STOCK PURCH PLAN	Liability	Active
102000002320318	A/P MEDICAL REIMBURSEMENT	Liability	Active
102000002320319	A/P SCHOLARSHIP FUND	Liability	Active
102000002320321	HSA CONTRIBUTIONS	Liability	Active
102000002320323	RETIREE HEALTH INS CONTRIBUTIONS	Liability	Active
102000002320401	A/P UNCLAIMED DEPOSITS & REF.	Liability	Active
102000002320402	A/P UNCLAIMED CREDIT BALANCE REFUNDS	Liability	Active
102000002320500	A/P CUSTOMER REFUNDS	Liability	Active
102000002320501	A/P DUPLICATE CUSTOMER DEPOSITS	Liability	Active
102000002320502	A/P CUSTOMER CREDIT BALANCES	Liability	Active
102000002320503	A/P SUNDRY CUSTOMER CREDIT BALANCES	Liability	Active
102000002320600	A/P LI-EAP OVERCOLLECTED FUNDS	Liability	Active
102000002320701	A/P CDFA FOR EEBB PROGRAM - 2015	Liability	Active
102000002321500	ACCTS PAYABLE OTHER	Liability	Active
102000002322101	GROUP NET METERING ALLOCATION PAYABLE	Liability	Active
102000002323000	DEPENDENT CARE DEDUC & REIMB	Liability	Active
102000002323200	OPTIONAL LIFE INS DEDUCTION	Liability	Active
102000002323300	OPTIONAL AD&D DEDUCTION	Liability	Active
102000002323400	LONG TERM CARE INS DEDUCTION	Liability	Active
102000002323500	HOME/AUTO INS DEDUCTION	Liability	Active
102000002330000	NOTE PAYABLE - CASHPOOL	Liability	Active
102000002340000	A/P ASSOC CO-VOUCHERS	Liability	Active
102000002340102	A/P ASSOC CO-FLEXI ONLY USC	Liability	Active
102000002340105	A/P ASSOC COS - SERVICE BILL	Liability	Active
102000002340112	A/P ASSOC COS - USC	Liability	Active
102000002340115	A/P ASSOC COS - UC	Liability	Active
102000002340121	A/P ASSOC COS - FEDCO	Liability	Active
102000002340133	A/P ASSOC COS - GSG	Liability	Active
102000002350100	CUSTOMER DEPOSITS	Liability	Active
102000002350200	CUSTOMER BILLED DEPOSITS	Liability	Active
102000002360130	FED INC TAX CURRENT	Liability	Active
102000002360131	FED INC TAX PRIOR	Liability	Active
102000002360230	STATE BPT-CURRENT	Liability	Active

102000002360231	STATE BPT-PRIOR	Liability	Active
102000002360240	STATE TAX-CURRENT	Liability	Active
102000002360241	STATE TAX - PRIOR	Liability	Active
102000002360242	NH CONSUMPTION TAX	Liability	Active
102000002360243	NH CONSUMPTION TAX WRITE-OFF	Liability	Active
102000002360306	ACCR TAXES MASS UNEMPLOYMENT	Liability	Active
102000002360310	ACCR TAXES FICA	Liability	Active
102000002360410	TAXES FEDERAL UNEMPLOYMNT	Liability	Active
102000002360610	TAXES UNEMPLOYMNT-NH	Liability	Active
102000002370000	INTEREST ACCRUED	Liability	Active
102000002370100	ACCR INTEREST FUNDED DEBT	Liability	Active
102000002380100	DIVIDENDS DECLARED PREF	Liability	Active
102000002380200	DIVIDENDS DECLARED COMMON	Liability	Active
102000002410310	EMPL FICA WITHHOLDING TAX	Liability	Active
102000002410410	EMPL FED WITHHOLDING TAX	Liability	Active
102000002410611	EMPL STATE WITHHOLDING TAX - MA	Liability	Active
102000002410616	EMPL STATE WITHHOLDING TAX - ME	Liability	Active
102000002420000	MISC ACCRUED LIABILITIES	Liability	Active
102000002420102	ACCRUED PENS FUND PAY	Liability	Active
102000002420105	ACCRUED LEGAL FEES-CORPORATE	Liability	Active
102000002420106	ACCRUED LEGAL FEES-REGULATORY	Liability	Active
102000002420144	ACCRUED RPS	Liability	Active
102000002420320	ACCRUED HEALTH INSURANCE - NON UNION	Liability	Active
102000002420325	ACCRUED DENTAL INSURANCE	Liability	Active
102000002420408	ACCRUED LEGAL-CLAIMS AND LITIGATION	Liability	Active
102000002420511	ACCRUED LEGAL MISC - FLOW THRU OR BS	Liability	Active
102000002420600	FAS 158 ADJ SERP CURRENT	Liability	Active
102000002420800	ACCRUED AUDIT FEES	Liability	Active
102000002422600	ACCRUED INCENTIVE COMPENSATION	Liability	Active
102000002423000	ACCRUED VACATION	Liability	Active
102000002423110	INSURANCE CLAIMS-UES	Liability	Active
102000002423200	ACCOUNTS PAYABLE ACCRUAL	Liability	Active
102000002423210	ACCOUNTS PAYABLE ACCRUAL - BS	Liability	Active
102000002423300	UNEARNED REVENUE-MISC	Liability	Active
102000002423400	ACCRUED POSTAGE	Liability	Active
102000002428600	ACCRUED EMERGENCY STORM COSTS	Liability	Active
102000002429000	REGULATORY LIABILITIES-CURRENT	Liability	Active
102000002430100	OPER LEASE OBLIG - CURRENT	Liability	Active
102000002530010	REGULATORY LIAB-PURCH POWER CONTRACTS	Liability	Active
102000002530104	CUSTOMER GIFT CERTIFICATE	Liability	Active
102000002530200	SYSTEM BENEFIT CHARGE - LI-EAP RESERVE	Liability	Active
102000002530403	ACCRUED SFAS 106 LIABILITY	Liability	Active
102000002530411	FAS 158 ADJ - PENSION	Liability	Active
102000002530413	FAS 158 ADJ - PBOP	Liability	Active
102000002530414	FAS 158 ADJ - SERP	Liability	Active
102000002533601	ACCRUED RPS - TYPE 1	Liability	Active
102000002540400	REGULATORY LIABILITY-COST OF REMOVAL	Liability	Active
102000002540500	REGULATORY LIABILITY-SFAS 109 FED	Liability	Active
102000002540501	REGULATORY LIABILITY-ASC 740	Liability	Active

102000002540503	REGULATORY LIABILITY-ASC 740 REV REQ	Liability	Active
102000002820130	DEF FIT - OTHER	Liability	Active
102000002820131	DEF FIT - ACCEL DEPR	Liability	Active
102000002820134	DEF FIT - SFAS 106-OPEB	Liability	Active
102000002820135	DEF FIT - PENSION FAS 87	Liability	Active
102000002820136	DEF FIT - DEBT DISC EXP	Liability	Active
102000002820142	DEF FIT - DEFD RATE CASE & RESTR	Liability	Active
102000002820147	DEF FIT - PENSION FAS 87 REG ASSET	Liability	Active
102000002820149	DEF FIT - SFAS 106 OPEB REG ASSET	Liability	Active
102000002820150	DEF FIT - BAD DEBT REG ASSET	Liability	Active
102000002820151	DEF FIT - ITC	Liability	Active
102000002820155	DEF FIT - DER INVESTMENT AMORT	Liability	Active
102000002820159	DEF FIT- FAS 158 PBOP	Liability	Active
102000002820160	DEF FIT- PENSION FAS 158	Liability	Active
102000002820161	DEF FIT - MERGER COSTS	Liability	Active
102000002820162	DEF FIT - INDENTURE COSTS	Liability	Active
102000002820163	DEF FIT- SERP FAS 158	Liability	Active
102000002820164	DEF FIT- SFAS 109 REG ASSET STATE	Liability	Active
102000002820166	DEF FIT- R & D	Liability	Active
102000002820167	DEF FIT- STORM RESTORATION	Liability	Active
102000002820168	ADIT-UTILITY PLANT DIFFERENCES	Liability	Active
102000002820199	DEF FIT - DEBIT BALANCE RECLASS	Liability	Active
102000002820231	DEF SIT - ACCEL DEPR	Liability	Active
102000002820233	DEF SIT - RETIREMENT LOSS	Liability	Active
102000002820234	DEF SIT - SFAS 106 -OPEB	Liability	Active
102000002820235	DEF SIT - PENSION FAS 87	Liability	Active
102000002820236	DEF SIT - DEBT DISC EXP	Liability	Active
102000002820242	DEF SIT - DEFD RATE CASE & RESTR	Liability	Active
102000002820247	DEF SIT - PENSION FAS87 REG ASSET	Liability	Active
102000002820249	DEF SIT - SFAS 106 OPEB REG ASSET	Liability	Active
102000002820250	DEF SIT - BAD DEBT REG ASSET	Liability	Active
102000002820255	DEF SIT - DER INVESTMENT AMORT	Liability	Active
102000002820259	DEF SIT- FAS 158 PBOP	Liability	Active
102000002820260	DEF SIT- PENSION FAS 158	Liability	Active
102000002820261	DEF SIT - MERGER COSTS	Liability	Active
102000002820262	DEF SIT - INDENTURE COSTS	Liability	Active
102000002820263	DEF SIT- SERP FAS 158	Liability	Active
102000002820264	DEF SIT- SFAS 109 REG ASSET STATE	Liability	Active
102000002820266	DEF SIT- R & D	Liability	Active
102000002820267	DEF SIT- STORM RESTORATION	Liability	Active
102000002820299	DEF SIT - DEBIT BALANCE RECLASS	Liability	Active
102000002820300	DEF FIT (SFAS 109) GROSS-UP FED	Liability	Active
102000002820303	TCJA REV REQ GROSS-UP	Liability	Active
102000002820501	ACCUM DEF (ASC 740) GROSS-UP	Liability	Active
102000002821138	DEF FIT - BAD DEBT	Liability	Active
102000002821139	DEF FIT - ACCRUED REVENUE	Liability	Active
102000002821141	DEF FIT - PREPAID PROPERTY TAX	Liability	Active
102000002821238	DEF SIT - BAD DEBT	Liability	Active
102000002821239	DEF SIT - ACCRUED REVENUE	Liability	Active

102000002821241	DEF SIT - PREPAID PROPERTY TAX	Liability	Active
102000002829159	DEF FIT - SFAS 158 PBOP	Liability	Active
102000002829160	DEF FIT - PENSION FAS 158	Liability	Active
102000002829163	DEF FIT - SFAS 158 SERP	Liability	Active
102000002829259	DEF SIT - SFAS 158 PBOP	Liability	Active
102000002829260	DEF SIT - PENSION FAS 158	Liability	Active
102000002829263	DEF SIT - SFAS 158 SERP	Liability	Active
102000232320000	COGENERATION- OVERCOLLECTION	Liability	Active
102000241730000	ACCRUED REV SBC-LBR	Assets	Active
102000321730000	ACCRUED REV-EXT DELIVERY	Assets	Active
102000321730001	ACC REV-DISPLACED DISTRIB REVENUE	Assets	Active
102000331730000	ACCRUED REV-STRANDED COSTS	Assets	Active
102000361730000	ACCRUED REV-DEFAULT SVC-NON-G1	Assets	Active
102000371730000	ACCRUED REV-DEFAULT SVC-G1	Assets	Active
102000421730000	ACCRUD REV-RENEW PORT STD COSTS-NON-G1	Assets	Active
102000431730000	ACCRUD REV-RENEW PORT STD COSTS-G1	Assets	Active
102000441730100	ACCRUED REVENUE-RGGI RES-NON LOW INCOME	Assets	Active
102000441730200	ACCRUED REVENUE-RGGI RES-LOW INCOME	Assets	Active
102000441730300	ACCRUED REVENUE-RGGI RES-C & I	Assets	Active
102000451730000	ACC REV RSO	Assets	Active
102000461730000	ACC REV ON TOU-SMART GRID	Assets	Active
102000471730000	ACCRUED REVENUE-STORM RECOVERY ADJ	Assets	Active
102000471828600	REG ASSET - EMERGENCY STORM RESTORATION	Assets	Active
102000481730100	ACCRUED REVENUE- EEBB RES	Assets	Active
102000482320700	A/P - CDFA FOR EEBB PROGRAM	Liability	Active
102001004191106	INT INC-NH EE RES NON LOW INC	Revenue	Active
102001004191306	INT INC-NH EE C & I	Revenue	Active
102001004191706	INT INC-NH EE RES LOW INC	Revenue	Active
102001004260400	ANHU ASSESSMENT	Expense	Active
102001004311106	INT EXP-NH EE RES NON LOW INC	Expense	Active
102001004311306	INT EXP-NH EE C & I	Expense	Active
102001004311706	INT EXP-NH EE RES LOW INC	Expense	Active
102001009081332	C&I LTG TA-G1-DSGN, ADM & MKTG	Expense	Active
102001009230002	OS LEGAL - MISC	Expense	Active
102001009236001	MARKET PLANNING AND PRICING	Expense	Active
102001009280100	REG COMM ASSESSMENT/FEES	Expense	Active
102001009280200	REG COMM EXP-MISC	Expense	Active
102001009280300	REG COMM EXP - LEGAL	Expense	Active
102001224190000	INTEREST INCOME - LIEAP RESERVE	Revenue	Active
102001224310000	INTEREST EXPENSE - LIEAP RESERVE	Expense	Active
102001244190000	INT INCOME-SBC-LBR	Revenue	Active
102001244310000	INT EXPENSE-SBC-LBR	Expense	Active
102001324190000	Int Income-External Delivery	Revenue	Active
102001324310000	Int Expense-External Delivery	Expense	Active
102001334190000	Int Income-Stranded Costs	Revenue	Active
102001334310000	Int Expense-Stranded Costs	Expense	Active
102001364190000	Int Income-Default Service-Non-G1	Revenue	Active
102001364310000	Int Expense-Default Service-Non-G1	Expense	Active
102001369280100	REG COMM - PUC ASSESSMENT - PS G1/NONG1	Expense	Active

102001369300099	DS ADMIN SERVICE COST - NON G1	Expense	Active
102001374190000	Int Income-Default Service-G1	Revenue	Active
102001374310000	Int Expense-Default Service-G1	Expense	Active
102001379300099	DS ADMIN SERVICE COST - G1	Expense	Active
102001424190000	INT INCOME-RENEW PORT STD COSTS-NON-G1	Revenue	Active
102001424310000	INT EXPENSE-RENEW PORT STD COSTS-NON-G1	Expense	Active
102001434190000	INT INCOME-RENEW PORT STD COSTS-G1	Revenue	Active
102001434310000	INT EXPENSE-RENEW PORT STD COSTS-G1	Expense	Active
102001454190000	INT INCOME-RSO	Revenue	Active
102001454310000	INT EXPENSE- RSO	Expense	Active
102001474190000	INT INC-STORM RECOVERY ADJ	Revenue	Active
102002004210300	POWER FACTOR CORRECTION INCOME	Revenue	Active
102002009230002	O/S LEGAL MARKETING	Expense	Active
102002464560000	OTHER ELECTRIC REVENUE-DOE FUNDING	Revenue	Active
102003004080310	TAXES F.I.C.A.	Expense	Active
102003004080410	TAXES FEDERAL UNEMPLOYMENT	Expense	Active
102003004080610	TAXES UNEMPLOYMENT-NH	Expense	Active
102003004260100	PENALTIES	Expense	Active
102003004261000	DONATIONS	Expense	Active
102003009200500	INCENTIVE COMPENSATION	Expense	Active
102003009260100	EMPL PENSION-401K	Expense	Active
102003009260201	FASB 87- PENSION - SERVICE	Expense	Active
102003009260220	FASB 87- PENSION - OTHER	Expense	Active
102003009260300	HEALTH INSUR MEDICAL ONLY	Expense	Active
102003009260301	HEALTH INS - EMP CONTR - MEDICAL ONLY	Expense	Active
102003009260303	HEALTH INS - DRUG SUBSIDY	Expense	Active
102003009260311	HEALTH INS - EMP CONTR - UES (UNION)	Expense	Active
102003009260400	EMPL BENEFIT-LIFE INSURANCE	Expense	Active
102003009260600	EMPLOYEE BENEFITS OTHER	Expense	Active
102003009260900	SFAS 106- PBOP - SERVICE	Expense	Active
102003009260919	SFAS 106- PBOP - OTHER	Expense	Active
102003009261000	EMPL PENSION FUND SERVICES	Expense	Active
102003009261200	DENTAL INSURANCE	Expense	Active
102003009261201	DENTAL INSURANCE - EMP CONTRIBUTION	Expense	Active
102003009261300	AD&D INSURANCE	Expense	Active
102003009261400	LTD INSURANCE	Expense	Active
102003009261500	RETIREE LIFE INSURANCE	Expense	Active
102003009261600	RELOCATION EXPENSE	Expense	Active
102003009262400	VISION INSURANCE	Expense	Active
102003009262401	VISION - EE CONTR	Expense	Active
102008004190200	INTEREST INCOME-CASH POOL	Revenue	Active
102008004190201	INTEREST INCOME - SPECIAL DEPOSITS	Revenue	Active
102008004192000	INTEREST INCOME- SPECIAL DEPOSITS	Revenue	Active
102008004210000	MISC REVENUE	Revenue	Active
102008004270000	INTEREST ON LT DEBT	Expense	Active
102008004280000	AMORT OF DEBT EXPENSE	Expense	Active
102008004300000	INT ON DEBT TO ASSOC CO	Expense	Active
102008004310200	INTEREST EXPENSE - CASHPOOL	Expense	Active
102008004370200	PREF DIVIDENDS 6%	Expense	Active

102008004380000	COMMON DIVIDENDS	Expense	Active
102008004390000	ADJMTS TO RETAINED EARNINGS	Expense	Active
102008004390001	CASH ADJMTS TO RETAINED EARNINGS	Expense	Active
102008004400000	ELEC REV RESIDENTIAL	Revenue	Active
102008004400002	Elec Rev Residential - Customer Charge	Revenue	Active
102008004400003	Elec Rev Residential - Block 1	Revenue	Active
102008004400004	Elec Rev Residential - Block 2	Revenue	Active
102008004400007	Elec Rev Residential - BPT	Revenue	Active
102008004400099	CONVERTED REVENUE RESIDENTIAL NON EXT	Revenue	Active
102008004403002	ELEC REV RESIDENTIAL - CUSTOMER CHG - Ext Sup	Revenue	Active
102008004403003	ELEC REV RESIDENTIAL - BLOCK 1 - Ext Sup	Revenue	Active
102008004403004	ELEC REV RESIDENTIAL - BLOCK 2 - Ext Sup	Revenue	Active
102008004403005	ELEC REV RESIDENTIAL - OFF PEAK - Ext Sup	Revenue	Active
102008004403099	CONVERTED REVENUE RESIDENTIAL EXT	Revenue	Active
102008004420099	CONVERTED REVENUE COMMERCIAL NON EXT	Revenue	Active
102008004420100	ELEC REV REGULAR GENERAL	Revenue	Active
102008004420102	Elec Rev Regular General - Customer Charge	Revenue	Active
102008004420103	Elec Rev Regular General -Block 1	Revenue	Active
102008004420106	Elec Rev Regular General - Demand Step 1	Revenue	Active
102008004420108	Elec Rev Regular General - Transf. Credit	Revenue	Active
102008004420110	Elec Rev Regular General - BPT	Revenue	Active
102008004420202	Elec Rev Large General - Customer Charge	Revenue	Active
102008004420203	Elec Rev Large General - Block 1	Revenue	Active
102008004420206	Elec Rev Large General - Demand Step 1	Revenue	Active
102008004420208	Elec Rev Large General - Transf. Credit	Revenue	Active
102008004423102	Elec Rev Regular General - Customer Charge - Ext Sup	Revenue	Active
102008004423103	Elec Rev Regular General - Block 1 - Ext Sup	Revenue	Active
102008004423106	Elec Rev Regular General - Demand Step 1 - Ext Sup	Revenue	Active
102008004423108	Elec Rev Regular General - Transfer Credit - Ext Sup	Revenue	Active
102008004423199	CONVERTED REVENUE COMMERCIAL EXT	Revenue	Active
102008004423202	Elec Rev Large General - Customer Charge - Ext Sup	Revenue	Active
102008004423203	Elec Rev Large General - Block 1 - Ext Sup	Revenue	Active
102008004423206	Elec Rev Large General - Demand Step 1 - Ext Sup	Revenue	Active
102008004423208	Elec Rev Large General - Transf. credit - Ext Sup	Revenue	Active
102008004423299	CONVERTED REVENUE INDUSTRIAL EXT	Revenue	Active
102008004429903	TOTAL LOCKED METERS	Revenue	Active
102008004429904	TOTAL METERS NOT READ	Revenue	Active
102008004440000	ELEC REV PUB ST LTG	Revenue	Active
102008004440100	ELEC REV UNMETERED SALES	Revenue	Active
102008004440199	CONVERTED REVENUE OUTDOOR LIGHTING NON EXT	Revenue	Active
102008004443000	ELEC REV PUB ST LTG - Ext Sup	Revenue	Active
102008004443099	CONVERTED REVENUE OUTDOOR LIGHTING EXT	Revenue	Active
102008004443100	ELEC REV UNMETERED SALES - Ext Sup	Revenue	Active
102008004450000	ELEC REV SALES TO PUB AUTH	Revenue	Active
102008004450100	Electric Revenue Lg. General	Revenue	Active
102008004450102	Municipal Regular General - Cust Charge	Revenue	Active
102008004450103	Municipal Regular General - Block 1	Revenue	Active
102008004450106	Municipal Regular General Demand - Step 1	Revenue	Active
102008004450108	Municipal Regular General - Transformer Credit	Revenue	Active

102008004450200	Electric Revenue Reg. General	Revenue	Active
102008004450202	Municipal Large General - Cust Charge	Revenue	Active
102008004450203	Municipal Large General - Block 1	Revenue	Active
102008004450206	Municipal Large General - Step 1	Revenue	Active
102008004450207	Municipal Large General - Step 2	Revenue	Active
102008004450208	Municipal Large General - Transformer Credit	Revenue	Active
102008004450299	CONVERTED REVENUE INDUSTRIAL NON EXT	Revenue	Active
102008004453102	Municipal Regular General Cust Charge - Ext Sup	Revenue	Active
102008004453103	Municipal Regular General Block 1 - Ext Sup	Revenue	Active
102008004453104	Municipal Regular General Block 2 - Ext Sup	Revenue	Active
102008004453105	Municipal Regular General Temp - Ext Sup	Revenue	Active
102008004453106	Municipal Regular General Demand Step 1 - Ext Sup	Revenue	Active
102008004453107	Municipal Regular General Step 2 - Ext Sup	Revenue	Active
102008004453108	Municipal Regular General Transformer Credit - Ext Sup	Revenue	Active
102008004453202	Municipal Large General Cust Charge - Ext Sup	Revenue	Active
102008004453203	Municipal Large General Block 1 - Ext Sup	Revenue	Active
102008004453204	Municipal Large General Block 2 - Ext Sup	Revenue	Active
102008004453205	Municipal Large General Temp - Ext Sup	Revenue	Active
102008004453206	Municipal Large General Step 1 - Ext Sup	Revenue	Active
102008004453207	Municipal Large General Step 2 - Ext Sup	Revenue	Active
102008004453208	Municipal Large General Transformer Credit	Revenue	Active
102008004490001	UNBILLED REVENUE - SEASONALITY	Revenue	Active
102008004495000	RATE RELIEF - ELEC	Revenue	Active
102008004500000	LATE PAYMENT CHARGES	Revenue	Active
102008004510000	DISC/RECON CHARGES	Revenue	Active
102008004510200	TEMPORARY SERVICE REVENUE	Revenue	Active
102008004540000	RENT ELEC PROP - CATV	Revenue	Active
102008004560000	OTHER ELEC REVENUES	Revenue	Active
102008004560100	LINE EXTENSION SURCHARGE	Revenue	Active
102008004561000	REV FROM TRANS OF ELEC OF OTHERS	Revenue	Active
102008009210108	BANK FEES & COMMITMENT FEES	Expense	Active
102008009210109	Credit Card Fees	Expense	Active
102008009210111	CREDIT RATING FEES	Expense	Active
102008009230000	OS- LEGAL CLAIMS AND LITIGATIONS	Expense	Active
102008009230001	OS LEGAL-CORPORATE	Expense	Active
102008009240000	PROPERTY INSURANCE	Expense	Active
102008009250000	D & O AND FIDUCIARY	Expense	Active
102008009250200	GENERAL LIABILITY	Expense	Active
102008009250202	GENERAL LIABILITY CLAIMS	Expense	Active
102008009250400	WORKERS COMPENSATION EXP	Expense	Active
102008009300200	TRUSTEE/REGISTRAR EXPENSE	Expense	Active
102008994510101	ENHANCED METER REVENUE - RES.	Revenue	Active
102008994510102	ENHANCED METER REVENUE - GEN.	Revenue	Active
102008994510200	INTERVAL DATA	Revenue	Active
102009005860400	INTERVAL DATA	Expense	Active
102009009020000	CUST ACCT METER READ EXP	Expense	Active
102009009020200	METER READINGTELEPHONE EXPENSE	Expense	Active
102009009211700	Telephone Services - Service Center-CAP	Expense	Active
102009009211701	Telephone Services - Service Center-SEA	Expense	Active

102010004030000	DEPRECIATION EXPENSE	Expense	Active
102010004032400	DEPRECIATION ELEC	Expense	Active
102010004040300	AMORTIZATION OF OTHER SOFTWARE	Expense	Active
102010004040400	CIS AMORTIZATION	Expense	Active
102010004070100	AMORTIZATION - EXCESS ADIT - BASE REV	Expense	Active
102010004070301	MERGER COST AMORTIZATION	Expense	Active
102010004070304	RATE CASE COST AMORTIZATION	Expense	Active
102010004070419	AMORTIZATION OF OTHER PBOP COST	Expense	Active
102010004070420	AMORTIZATION OF OTHER PENSION COST	Expense	Active
102010004070421	AMORT OF OTHER SERP COST	Expense	Active
102010004070600	DER INVESTMENT AMORTIZATION	Expense	Active
102010004070900	AMORT EXP-FAS 109 REG ASSET-FED	Expense	Active
102010004070901	AMORT EXP-FAS 109 REG LIABILITY- FED	Expense	Active
102010004070902	AMORT EXP-FAS 109 REG GROSS-UP-FED	Expense	Active
102010004073100	AMORTIZATION - STORM	Expense	Active
102010004080210	NH SURPLUS TAX	Expense	Active
102010004080218	NH BET TAX EXPENSE	Expense	Active
102010004080502	TAXES STATE UNEMP MA	Expense	Active
102010004080601	TAXES STATE SALES NH	Expense	Active
102010004080701	TAXES STATE GASOLINE	Expense	Active
102010004080801	TAXES STATE OTHER	Expense	Active
102010004080901	TAXES LOCAL PROPERTY	Expense	Active
102010004080902	TAXES LOCAL PROPERTY ABATEMENTS	Expense	Active
102010004081000	PAYROLL TAXES CAPITALIZED-CR	Expense	Active
102010004090130	FED INCOME TAX CURRENT	Expense	Active
102010004090131	FED INCOME TAX PRIOR	Expense	Active
102010004090132	FED INCOME TAX NON-OPER	Expense	Active
102010004090230	STATE INC TAX - CRNT -BPT	Expense	Active
102010004090231	STATE INC TAX - PRIOR -BPT	Expense	Active
102010004090232	STATE INC TAX - NON OP -BPT	Expense	Active
102010004100130	DEF FIT EXP - ACCEL DEPRECIATION	Expense	Active
102010004100134	DEF FIT EXP - SFAS 106 OPEB	Expense	Active
102010004100135	DEF FIT EXP - PENSION FAS 87	Expense	Active
102010004100136	DEF FIT EXP - CIAC	Expense	Active
102010004100138	DEF FIT EXP - BAD DEBT	Expense	Active
102010004100139	DEF FIT EXP - ACCRUED REVENUE	Expense	Active
102010004100141	DEF FIT EXP - PREPAID PROP TAX	Expense	Active
102010004100142	DEF FIT EXP - RATE CASE & RESTR	Expense	Active
102010004100146	DEF FIT EXP-STATE TAXES	Expense	Active
102010004100147	DEF FIT EXP-PENSION FAS 87 REG ASSET	Expense	Active
102010004100149	DEF FIT EXP-SFAS 106 OPEB REG ASSET	Expense	Active
102010004100150	DEF FIT-BAD DEBT-REG ASSET	Expense	Active
102010004100154	DEF FIT EXP - DEBT DISC	Expense	Active
102010004100155	DEF FIT EXP - DER INVESTMENT AMORT	Expense	Active
102010004100161	DEF FIT EXP-MERGER COSTS	Expense	Active
102010004100162	DEF FIT EXP-MERGER COSTS	Expense	Active
102010004100164	DEF FIT EXP-SFAS109 REG ASSET STATE	Expense	Active
102010004100166	DEF FIT EXP- R&D	Expense	Active
102010004100167	DEF FIT EXP-STORM RESTORATION	Expense	Active

102010004100200	DEF SIT EXP - NH	Expense	Active
102010004100230	DEF SIT EXP-ACCEL DEPRECIATION	Expense	Active
102010004100234	DEF SIT EXP-SFAS 106 OPEB	Expense	Active
102010004100235	DEF SIT EXP-PENSION FAS 87	Expense	Active
102010004100236	DEF SIT EXP-CIAC	Expense	Active
102010004100238	DEF SIT EXP-BAD DEBT	Expense	Active
102010004100239	DEF SIT EXP-ACCRUED REVENUE	Expense	Active
102010004100241	DEF SIT EXP-PREPAID PROP TAX	Expense	Active
102010004100242	DEF SIT EXP- RATE CASE & RESTR	Expense	Active
102010004100247	DEF SIT EXP-PENSION FAS87 REG ASSET	Expense	Active
102010004100249	DEF SIT EXP-SFAS 106 OPEB REG ASSET	Expense	Active
102010004100250	DEF SIT-BAD DEBT-REG ASSET	Expense	Active
102010004100254	DEF SIT EXP- DEBT DISC	Expense	Active
102010004100255	DEF SIT EXP - DER INVESTMENT AMORT	Expense	Active
102010004100261	DEF SIT EXP-MERGER COSTS	Expense	Active
102010004100262	DEF SIT EXP-MERGER COSTS	Expense	Active
102010004100264	DEF SIT EXP-SFAS109 REG ASSET STATE	Expense	Active
102010004100266	DEF SIT EXP- R&D	Expense	Active
102010004100267	DEF SIT EXP-STORM RESTORATION	Expense	Active
102010004100303	DEF TAX - TCJA REV REQ GROSS-UP	Expense	Active
102010004110110	DEF TAX - DISCRETE TAX PROVISION	Expense	Active
102010004190900	INTEREST INCOME - MAJOR STORM RESERVE	Revenue	Active
102010004193299	WORKING COST OF CAPITAL - EDC	Revenue	Active
102010004193699	DS WORKING COST OF CAPITAL - NON G1	Revenue	Active
102010004193799	DS WORKING COST OF CAPITAL - G1	Revenue	Active
102010004194299	RPS WORKING COST OF CAPITAL - NON G1	Revenue	Active
102010004194399	RPS WORKING COST OF CAPITAL - G1	Revenue	Active
102010004210001	USC BELOW THE LINE RECLASS	Expense	Active
102010004260100	PENALTIES	Expense	Active
102010004260101	USC BELOW THE LINE RECLASS	Expense	Active
102010004260102	USC PENALTIES RECLASS	Expense	Active
102010004310900	INT EXPENSE-OTHER	Expense	Active
102010004320000	AFUDC-BORROWED FUNDS	Revenue	Active
102010004490000	UNBILLED REVENUE	Revenue	Active
102010004490001	UNBILLED REVENUE-RES (STAT ONLY)	Revenue	Active
102010004490002	UNBILLED REVENUE-LARGE C&I (STAT ONLY)	Revenue	Active
102010004490003	UNBILLED REVENUE-SMALL C&I (STAT ONLY)	Revenue	Active
102010004490027	ACCRUED REVENUE - NON DIST BAD DEBT	Revenue	Active
102010004491001	ACCRUED REVENUE - TCJA 2018	Revenue	Active
102010004491002	UNBILLED REVENUE - SEASONALITY	Revenue	Active
102010004491100	ACCRUED REVENUE VMP EXPENSES	Revenue	Active
102010004540200	MISC RENT	Revenue	Active
102010004560000	OTHER ELEC REVENUES	Revenue	Active
102010005570100	USC-ELECT PRODUCTION ADMIN	Expense	Active
102010005610100	USC - NERC COMPLIANCE	Expense	Active
102010005800200	USC - ELECTRIC DISTRIBUTION	Expense	Active
102010005800201	USC - ELECTRIC DISTRIBUTION-CAP	Expense	Active
102010005881100	SERVICE CENTER CAPITALIZED	Expense	Active
102010005881101	SERVICE CENTER CAPITALIZED - SEA	Expense	Active

102010005900600	UNPROD TIME/CAPITALIZED	Expense	Active
102010005900601	STATION UNPROD TIME CAPITALIZED	Expense	Active
102010005930201	RELIABILITY ENHANCEMENT PROGRAM - ACCRUAL	Expense	Active
102010005930400	USC-VEGETATION MANAGEMENT	Expense	Active
102010005930401	DIST VEG CONTROL - ACCRUAL	Expense	Active
102010005930402	FAIRPOINT/TDS BILLING	Expense	Active
102010005930501	STORM COSTS	Expense	Active
102010009030600	USC - CUSTOMER ACCOUNTING	Expense	Active
102010009040000	PROVISION FOR DOUBTFUL ACCTS	Expense	Active
102010009040027	PROVISION FOR DOUBTFUL ACCCTS-NON-DIST	Expense	Active
102010009200500	INCENTIVE COMPENSATION CAPITALIZED	Expense	Active
102010009200900	PAYROLL ACCRUAL	Expense	Active
102010009211100	SERVICE CENTER CAPITALIZED	Expense	Active
102010009211900	TELEPHONE SERVICES CAPITALIZED	Expense	Active
102010009211901	TELEPHONE SERVICES CAPITALIZED - SEA	Expense	Active
102010009230200	OUTSIDE SERVICES-AUDIT	Expense	Active
102010009230300	OS UNITIL SERVICE CORP	Expense	Active
102010009230301	OS UNITIL SERVICE CORP-CAP	Expense	Active
102010009230305	USC OUTSIDE SERVICES-DIRECT CHGS	Expense	Active
102010009230307	DIRECT CHARGES CAPITALIZED	Expense	Active
102010009230308	USC ALLOCATED PBOP EXPENSE	Expense	Active
102010009230309	USC ALLOCATED SERP EXPENSE	Expense	Active
102010009230310	USC ALLOCATED PENSION EXPENSE	Expense	Active
102010009230400	OS OTHER	Expense	Active
102010009240001	PROPERTY INS CAPITALIZED	Expense	Active
102010009250201	GEN LIAB CAPITALIZED	Expense	Active
102010009250401	WORKERS COMP CAPITALIZED	Expense	Active
102010009260101	401K CAPITALIZED	Expense	Active
102010009260210	PENSION - USC ALLOC - SVC	Expense	Active
102010009260230	PENSION - USC ALLOC - OTHER	Expense	Active
102010009260299	FASB 87 - YEAR END ACCRUAL ADJ	Expense	Active
102010009260302	EMPLOYEE BENEFIT ACCRUAL ADJ	Expense	Active
102010009260500	BENEFIT COST CAPITALIZED	Expense	Active
102010009260800	PENSION - SVC CAPITALIZED	Expense	Active
102010009260812	PENSION - USC ALLOC - SVC CAPITALIZED	Expense	Active
102010009260820	PENSION - OTHER - CAPITALIZED	Expense	Active
102010009260830	PENSION - USC ALLOC - OTHER DEFERRED	Expense	Active
102010009260910	PBOP - USC ALLOC - SVC	Expense	Active
102010009260929	PBOP - USC ALLOC - OTHER	Expense	Active
102010009260999	SFAS 106 - PBOP - YE ACCRUAL ADJ	Expense	Active
102010009261110	SERP - USC ALLOC - SVC	Expense	Active
102010009261131	SERP - USC ALLOC - OTHER	Expense	Active
102010009261700	PBOP - SVC CAPITALIZED	Expense	Active
102010009261712	PBOP - USC ALLOC - SVC CAPITALIZED	Expense	Active
102010009261719	PBOP - OTHER - CAPITALIZED	Expense	Active
102010009261729	PBOP - USC ALLOC - OTHER DEFERRED	Expense	Active
102010009261812	SERP - USC ALLOC - SVC CAPITALIZED	Expense	Active
102010009261831	SERP - USC ALLOC - OTHER DEFERRED	Expense	Active
102010009270000	FRANCHISE FEE	Expense	Active

102010009301000	MISC EXP - PANDEMIC COSTS	Expense	Active
102010009302000	MISC EXPENSE	Expense	Active
102010009999997	DISCOUNTS LOST	Expense	Active
102010009999998	DISCOUNT	Expense	Active
102010009999999	UES SUSPENSE	Expense	Active
102010324490100	ACCRUED REV-DISPLACED DISTRIBUTION REVENUE	Revenue	Active
102012005882000	INTERCONNECTION COSTS/ FUNDS	Expense	Active
102012009230000	OS LEGAL - ENGINEERING	Expense	Active
102013009210300	DUES & SUBSCRIPTIONS	Expense	Active
102013009280300	REG COMM EXP - LEGAL	Expense	Active
102013365551000	GIS COST COMMON	Expense	Active
102013365555500	RGGI AUCTION PROCEEDS	Expense	Active
102013365556502	TYPE 2 RPS - COMMON	Expense	Active
102013365556503	TYPE 3 RPS - COMMON	Expense	Active
102013369230000	OS LEGAL - LEGAL-DS-COMMON	Expense	Active
102013369231100	CONSULTING OUTSIDE SERVICES-DS-COMMON	Expense	Active
102013369280300	REG COMM EXP-LEGAL-DS-COMMON	Expense	Active
102015009210300	DUES & SUBSCRIPTIONS	Expense	Active
102015009230000	OS- LEGAL CLAIMS AND LITIGATIONS	Expense	Active
102021004260100	DONATIONS	Expense	Active
102021004260501	OTHER INC DED - CUSTOMER RELATIONS	Expense	Active
102021004310400	INTEREST ON CUSTOMER DEPOSITS	Expense	Active
102021009030200	BILLG/ACCT FORMS/SUPPLIES	Expense	Active
102021009030400	POSTAGE	Expense	Active
102021009030501	MISC COST OF COLLECTIONS	Expense	Active
102021009030502	COST OF COLLECTIONS	Expense	Active
102021009030503	SUNDRY COST OF COLLECTIONS	Expense	Active
102021009030504	O/S VENDOR SERVICES - MAILROOM	Expense	Active
102021009030800	MISC CUSTOMER RELATIONS	Expense	Active
102021009031000	O/S REMITTANCE LOCK BOX	Expense	Active
102021009040000	PROVISION FOR DOUBTFUL ACCTS	Expense	Active
102021009040001	BD EXP CIS G-1 - DIST	Expense	Active
102021009040002	BD EXP CIS G-2 - DIST	Expense	Active
102021009040005	BD EXP CIS D-RES-DIST	Expense	Active
102021009040030	BD EXP CIS OL-DIST	Expense	Active
102021009040065	BD EXP CIS SP CT-DIST	Expense	Active
102021009040100	PROVISION FOR DOUBTFUL ACCTS-SUNDRY	Expense	Active
102021009049999	BD EXP CIS CONVERTED WRITE OFF	Expense	Active
102021009090100	NEIGHBOR HELPING NEIGHBOR	Expense	Active
102021009210109	CREDIT CARD FEES	Expense	Active
102022009133102	ADVERTISING-SHARED SERVICES/SAFETY	Expense	Active
102022009212400	SAFETY - SHARED SERVICES	Expense	Active
102022009230000	OS-LERS LOGICA	Expense	Active
102022009231500	OS - Emergency Mgmt & Compliance	Expense	Active
102024004260100	COMMUNITY DONATIONS	Expense	Active
102024004260101	USC DONATIONS	Expense	Active
102024004260200	SOCIAL ADVERTISING -BELOW LINE	Expense	Active
102024004260400	CIVIC ACTIVITIES-STATE	Expense	Active
102024004260401	CIVIC ACTIVITIES-FEDERAL	Expense	Active

102024004260410	USC NH CIVIC ACTIVITIES (USC BILL ONLY)	Expense	Active
102024004261600	COMMUNITY SPONSORSHIPS	Expense	Active
102024009090100	SOCIAL ADVERTISING	Expense	Active
102024009095200	OUTREACH AND EDUCATION	Expense	Active
102024009135300	CUSTOMER COMMUNICATION	Expense	Active
102024009230900	OUTSIDE SERVICES	Expense	Active
102024009305400	MEDIA SERVICES	Expense	Active
102024009306000	EMERGENCY COMMUNICATIONS	Expense	Active
102028005810000	COMMUNICATION SYSTEM EXP UES	Expense	Active
102028005930400	VMP FIELD STAFF NH	Expense	Active
102028005930410	MAINTENANCE CIRCUIT PRUNING	Expense	Active
102028005930411	HAZARD TREE MITIGATION	Expense	Active
102028005930412	MID-CYCLE REVIEW	Expense	Active
102028005930413	FORESTRY RELIABILITY ASSESSMENT	Expense	Active
102028005930414	BRUSH REMOVAL	Expense	Active
102028005930415	POLICE FLAGGER COSTS	Expense	Active
102028005930416	SUB TRANSMISSION VEGETATION CONTROL	Expense	Active
102028005930417	UES REP FORESTRY	Expense	Active
102028005930418	VMP STORM HARDENING	Expense	Active
102028005930420	CORE WORK - CUSTOMER REQUESTS	Expense	Active
102028005930421	CORE WORK - STORM EMERGENCY REQUESTS	Expense	Active
102028005930422	CORE WORK - HOT SPOTTING	Expense	Active
102028005930423	CORE WORK - MAKE SAFE	Expense	Active
102028005930424	CORE WORK - TREE PLANTING	Expense	Active
102028005930425	VMP SCHEDULING & PLANNING	Expense	Active
102028005930440	SUBSTATION SPRAYING	Expense	Active
102028009020000	CUST ACCT METER READ EXP	Expense	Active
102028009210200	TRAVEL & MEALS - FORESTRY	Expense	Active
102028009210300	DUES & SUBSCRIPTIONS - FORESTRY	Expense	Active
102028009210400	TELEPHONE EXPENSE - FORESTRY	Expense	Active
102028009212000	TRAINING & SEMINARS - FORESTRY	Expense	Active
102028009350601	MAINTENANCE SOFTWARE DISPATCH	Expense	Active
102050001050000	PLANT HELD FOR FUTURE USE	Assets	Active
102050001080200	ACCUM DEPR TRANSP PLANT	Assets	Active
102050001080202	TRANPS PLANT SALVAGE	Assets	Active
102050001110100	ACCUM AMORT LEASEHOLD IMPROV	Assets	Active
102050001110101	LEASE IMPROV RETIREMENTS	Assets	Active
102050001110601	INTANGIBLE RETIREMENTS	Assets	Active
102050001210000	NON UTILITY PROPERTY	Assets	Active
102050001540100	MATERIALS & SUPPLIES GENERAL	Assets	Active
102050001630000	STORES EXPENSE UNDISTRIBUTED	Assets	Active
102050001650100	PREPAID PROPERTY INSURANCE - CAPITAL	Assets	Active
102050001650104	PREPAID WORKERS COMP. INS - CAPITAL	Assets	Active
102050001830000	PRELIM. SURVEY & INVESTIGATION	Assets	Active
102050001840102	SUSP CLEARING LIGHT TRUCKS	Assets	Active
102050001840103	SUSP CLEARING HEAVY TRUCKS	Assets	Active
102050001840400	SUSP CLEAR EXEMPT STOCK	Assets	Active
102050001840401	SUSP CLEAR UNDG EXEMPT STOCK	Assets	Active
102050001841201	LT MAIN & PARTS	Assets	Active

102050001841202	LT LEASING	Assets	Active
102050001841203	LT FUEL	Assets	Active
102050001841204	LT TAXES, REG, INS, TOLLS	Assets	Active
102050001841205	LT OTHER	Assets	Active
102050001841301	HT MAINT & PARTS	Assets	Active
102050001841302	HT LEASING	Assets	Active
102050001841303	HT FUEL	Assets	Active
102050001841304	HT TAXES, REG, INS, TOLLS	Assets	Active
102050001841305	HT OTHER	Assets	Active
102050001850100	TEMPORARY SERVICES	Assets	Active
102050002320320	BCBS CLAIMS SETTLEMENT	Liability	Active
102050002420104	ACCRUED LEGAL FEES-LOCAL - CAPITAL	Liability	Active
102050002520000	CUSTOMER ADVANCES FOR CONSTR.	Liability	Active
102050005600000	TRANS OPER GEN SUPERVISION-CAP	Expense	Active
102050005600001	SUB TRANS OPER GEN SUPERVISION SUB CAP	Expense	Active
102050005630000	SUB TRANS OPER OVERHEAD LINES-CAP	Expense	Active
102050005630100	SUB TRANS OPER PATROL LINES-CAP	Expense	Active
102050005630200	TRANS OPER POLE TESTS-CAP	Expense	Active
102050005670000	SUB TRANS OPER RENTS-CAP	Expense	Active
102050005680000	SUB TRANS MAINT GENERAL SUPERVISION-CAP	Expense	Active
102050005680001	SUB TRANS MAINT GENERAL SUPERVISION SUB CAP	Expense	Active
102050005710100	T MAINT O/H LINES UNSCHEDULED-CAP	Expense	Active
102050005710200	T MAINT O/H LINES SCHEDULED-CAP	Expense	Active
102050005800000	DIST OPER GEN SUPERVISION-CAP	Expense	Active
102050005800020	UNALLOWABLE MEALS EXP-CAP	Expense	Active
102050005810000	LOAD DISPATCHING (DISTRIBUTION)-CAP	Expense	Active
102050005820100	DIST OPER STATION CHECKS-CAP	Expense	Active
102050005820201	DIST OPS STATION SNOW/OUTSIDE-CAP	Expense	Active
102050005820202	DIST OPS STATION SNOW/INSIDE-CAP	Expense	Active
102050005820203	DIST OPS STATION GRASS/MOWING OUTSIDE-CAP	Expense	Active
102050005820204	DIST OPS STATION SPRAYING-CAP	Expense	Active
102050005830000	DIST OPER O/H LINE SWITCHING-CAP	Expense	Active
102050005830100	DIST OPER PATROL LINES-CAP	Expense	Active
102050005830200	DIST OPER TRANS CHECK/CHANGE-CAP	Expense	Active
102050005830300	DIST LOAD STUDIES-CAP	Expense	Active
102050005830400	STANDBY TIME LINE DEPT-CAP	Expense	Active
102050005830401	STANDBY TIME STATION CREW	Expense	Active
102050005830500	OVHD DIST INSPECT-NON MAINT AREA-CAP	Expense	Active
102050005830600	OVHD DIST INSPECT-MAINT AREA-CAP	Expense	Active
102050005840100	DIST OPER URD LINE EXP-CAP	Expense	Active
102050005840200	DIST OPER DIG SAFE EXP-CAP	Expense	Active
102050005840300	DIST OPER MANHOLE CHECK-CAP	Expense	Active
102050005840400	UNDERGROUND EQUIPMENT INSPECTIONS-CAP	Expense	Active
102050005850100	DIST OPER ST LIGHT EXP-CAP	Expense	Active
102050005850200	DIST OPER ST LIGHT GROUP REPL-CAP	Expense	Active
102050005860000	DIST OPER GEN METER EXP-CAP	Expense	Active
102050005860100	METER TEST-CAP	Expense	Active
102050005860200	METER ORDERS-CAP	Expense	Active
102050005860400	INTERVAL DATA-CAP	Expense	Active

102050005860600	TIE POINT METERING-CAP	Expense	Active
102050005870000	DIST OP GEN CUST PREMISE WORK-CAP	Expense	Active
102050005870100	DIST OPER CUSTOMER EQUIP-CAP	Expense	Active
102050005870200	DIVERSION INVESTIGATION-CAP	Expense	Active
102050005880100	ADMINISTRATIVE EXPENSES - SHARED MCGUIRE ST	Expense	Active
102050005880200	CUSTODIAL SERVICE & SUPPLY-CAP	Expense	Active
102050005880400	KITCHEN SUPPLY_ SNOW_ GRASS-CAP	Expense	Active
102050005880500	DIST SYSTEM TRAINING-CAP	Expense	Active
102050005880600	METERING SYSTEM TRAINING-CAP	Expense	Active
102050005880700	SUB STATION TRAINING	Expense	Active
102050005881200	SVC CNTR EXPENSED-CAP	Expense	Active
102050005881300	ENVIRONMENTAL - CAPITAL	Expense	Active
102050005889900	COMPANY USE-CAP	Expense	Active
102050005900000	DIST MAINT GENERAL SUPERVISION-CAP	Expense	Active
102050005900001	DIST MAINT GENERAL SUPERVISION SUBSTATION	Expense	Active
102050005900100	UNPROD TIME/SICKNESS-CAP	Expense	Active
102050005900101	STATION UNPROD TIME SICK	Expense	Active
102050005900200	UNPROD TIME/WEATHER-CAP	Expense	Active
102050005900201	STATION UNPROD TIME WEATHER	Expense	Active
102050005900300	UNPROD TIME/HOLIDAYS-CAP	Expense	Active
102050005900301	STATION UNPROD TIME HOLIDAY	Expense	Active
102050005900400	UNPROD TIME/VACATION-CAP	Expense	Active
102050005900401	STATION UNPROD TIME VACATION	Expense	Active
102050005900500	UNPROD TIME/OTHER-CAP	Expense	Active
102050005900501	STATION UNPROD TIME OTHER	Expense	Active
102050005920100	DIST MAINT STAT EQUIP UNSCHED-CAP	Expense	Active
102050005920200	DIST MAINT STAT EQUIP ANNUAL-CAP	Expense	Active
102050005920300	DIST MAINT STAT EQUIP CYCLE-CAP	Expense	Active
102050005920500	DIST MAINT MOBILE SUB-CAP	Expense	Active
102050005930100	DIST MAINT UNSCHEDULED-CAP	Expense	Active
102050005930200	DIST MAINT SCHEDULED-CAP	Expense	Active
102050005930201	RELIABILITY INSPECTIONS	Expense	Active
102050005930202	RELIABILITY MAINTENANCE & REPAIRS	Expense	Active
102050005930500	DIST STORM TROUBLE-CAP	Expense	Active
102050005940000	DIST MAINT U/G LINES-CAP	Expense	Active
102050005950000	DIST MAINT TRANSFORMER REPAIR-CAP	Expense	Active
102050005960000	DIST MAINT ST LIGHT REPAIR-CAP	Expense	Active
102050005970000	DIST MAINT METER REPAIR-CAP	Expense	Active
102050005970100	AMI COMMUNICATIONS AND TROUBLESHOOTING (SUB STATION)	Expense	Active
102050005980000	DIST MAINT MISC EQUIPMENT-CAP	Expense	Active
102050005980100	DIST MAINT SCADA SYSTEM-CAP	Expense	Active
102050005980200	DIST MAINT COMMUNICATION EQUIP-CAP	Expense	Active
102050009020000	CUST ACCTS METER READ EXP-CAP	Expense	Active
102050009030000	CREDIT DISCONNECTION-CAP	Expense	Active
102050009030700	MISC CREDIT EXPENSE-CAP	Expense	Active
102050009200000	A&G SALARIES-CAP	Expense	Active
102050009210100	GEN OFFICE SUPPLIES & EXP-CAP	Expense	Active
102050009210120	UNALLOWABLE MEALS EXP-CAP	Expense	Active
102050009211700	Telephone Services - Service Center-CAP	Expense	Active

102050009211800	Telephone Services - All Others - Capital	Expense	Active
102050009213000	DUES TO ORGANIZATIONS	Expense	Active
102050009230000	OS LEGAL-LOCAL-CAP	Expense	Active
102050009250100	INJURIES & DAMAGES SAFETY-CAP	Expense	Active
102050009260600	Employee Benefits Other - Cap	Expense	Active
102050009300100	GENERAL ADVERTISING-CAP	Expense	Active
102050009301000	MISC EXP - PANDEMIC COSTS - CAPITAL	Expense	Active
102053009260300	HEALTH INSUR MEDICAL ONLY	Expense	Active
102058009250400	WORKERS COMPENSATION EXP	Expense	Active
102060001050000	PLANT HELD FOR FUTURE USE	Assets	Active
102060001080200	ACCUM DEPR TRANSP PLANT	Assets	Active
102060001080202	TRANSP PLANT SALVAGE	Assets	Active
102060001110100	ACCUM AMORT LEASEHOLD IMPROV	Assets	Active
102060001110101	LEASE IMPROV RETIREMENTS	Assets	Active
102060001110601	INTANGIBLE RETIREMENTS	Assets	Active
102060001540100	MATERIALS & SUPPLIES GENERAL	Assets	Active
102060001630000	UNDISTRIB STORES EXPENSE	Assets	Active
102060001630100	STOREROOM OPERATING EXPENSE	Assets	Active
102060001630200	STOCK OVER & SHORT	Assets	Active
102060001630300	OBSOLETE STOCK	Assets	Active
102060001650100	PREPAID PROPERTY INSURANCE - SEACOAST	Assets	Active
102060001650104	PREPAID WORKERS COMP. INS - SEACOAST	Assets	Active
102060001830000	PRELIM SURVEY & INVESTIGATION	Assets	Active
102060001840102	SUSP CLEARING LIGHT TRUCKS	Assets	Active
102060001840103	SUSP CLEARING HEAVY TRUCKS	Assets	Active
102060001840400	SUSP CL O/H EXEMPT STOCK	Assets	Active
102060001840401	SUSP CL URD EXEMPT STOCK	Assets	Active
102060001841201	LT MAINT & PARTS	Assets	Active
102060001841202	LT LEASING	Assets	Active
102060001841203	LT FUEL	Assets	Active
102060001841204	LT TAXES, REG, INS, TOLLS	Assets	Active
102060001841205	LT OTHER	Assets	Active
102060001841301	HT MAINT & PARTS	Assets	Active
102060001841302	HT LEASING	Assets	Active
102060001841303	HT FUEL	Assets	Active
102060001841304	HT TAXES, REG, INS, TOLLS	Assets	Active
102060001841305	HT OTHER	Assets	Active
102060001850100	TEMPORARY SERVICES	Assets	Active
102060002320320	BCBS CLAIMS SETTLEMENT	Liability	Active
102060002420104	ACCRUED LEGAL FEES-LOCAL - SEACOAST	Liability	Active
102060002520000	CUSTOMER ADVANCES FOR CONSTR.	Liability	Active
102060002530103	ST OF NH ESCROW ACCT-SEA	Liability	Active
102060005600000	TRANS OPER GEN SUPERVISION-SEA	Expense	Active
102060005600001	SUB TRANS OPER GEN SUPERVISION SUB-SEA	Expense	Active
102060005620001	SUB TRAN OP SWITCH STATION EXP-SNOW - SEA	Expense	Active
102060005620002	SUB TRAN OP SWITCH STATION EXP-MOWING/SPRAYING - SEA	Expense	Active
102060005630000	SUB TRANS OPER OVERHEAD LINES-SEA	Expense	Active
102060005630100	SUB TRANS OPER PATROL LINES-SEA	Expense	Active
102060005630200	SUB TRANS OPER POLE TESTS-SEA	Expense	Active

102060005670000	SUB TRANS OPER RENTS	Expense	Active
102060005680000	SUB TRANS MAINT GENERAL SUPERVISION-SEA	Expense	Active
102060005680001	SUB TRANS MAINT GEN SUPERVISION SUB - SEA	Expense	Active
102060005710100	SUB TRANS MAINT O/H LINES UNSCHEDULED-SEA	Expense	Active
102060005800000	DIST OPER GEN SUPERVISION-SEA	Expense	Active
102060005800020	UNALLOWABLE MEALS EXP-SEA	Expense	Active
102060005810000	LOAD DISPATCHING (DISTRIBUTION)-SEA	Expense	Active
102060005820100	DIST OPER STATION CHECKS-SEA	Expense	Active
102060005820201	DIST OPS SNOW/OUTSIDE -SEA	Expense	Active
102060005820202	DIST OPS SNOW/INSIDE - SEA	Expense	Active
102060005820203	DIST OPS STATION GRASS/MOWING OUTSIDE - SEA	Expense	Active
102060005820204	DIST OPS STATION /SPRAYING - SEA	Expense	Active
102060005830000	DIST OPER O/H LINE SWITCHING-SEA	Expense	Active
102060005830100	DIST OPER PATROL LINES-SEA	Expense	Active
102060005830200	DIST OPER TRANS CHECK/CHANGE-SEA	Expense	Active
102060005830400	STANDBY TIME LINE DEPT-SEA	Expense	Active
102060005830401	STANDBY TIME STATION CREW	Expense	Active
102060005830500	OVHD DIST INSPECT - NON MAINT AREA-SEA	Expense	Active
102060005830600	OVHD DIST INSPECT - MAINT AREA-SEA	Expense	Active
102060005840100	DIST OPER URD LINE EXP-SEA	Expense	Active
102060005840200	DIST OPER DIG SAFE EXP-SEA	Expense	Active
102060005840400	UNDERGROUND EQUIP INSPECTIONS-SEA	Expense	Active
102060005850100	DIST OPER ST LIGHT EXP-SEA	Expense	Active
102060005850200	DIST OP ST LIGHT GROUP REPL-SEA	Expense	Active
102060005860000	DIST OPER GEN METER EXP-SEA	Expense	Active
102060005860100	METER TEST-SEA	Expense	Active
102060005860200	METER ORDERS-SEA	Expense	Active
102060005860400	INTERVAL DATA-SEA	Expense	Active
102060005870000	DIST OP GEN CUST PREMISE WORK-SEA	Expense	Active
102060005870100	DIST OPER CUSTOMER EQUIP-SEA	Expense	Active
102060005870200	DIVERSION INVESTIGATION-SEA	Expense	Active
102060005880100	ADMINISTRATIVE EXPENSE-SEA	Expense	Active
102060005880200	CUSTODIAL SERVICE & SUPPLY-SEA	Expense	Active
102060005880300	BLDG SERVICE_ HEAT_ ELEC_ TEL-SEA	Expense	Active
102060005880400	KITCHEN SUPPLY_ SNOW_ GRASS-SEA	Expense	Active
102060005880500	DIST SYSTEM TRAINING-SEA	Expense	Active
102060005880600	METERING SYSTEM TRAINING-SEA	Expense	Active
102060005880700	SUB STATION TRAINING	Expense	Active
102060005881200	SVC CNTR EXPENSED-SEA	Expense	Active
102060005881300	ENVIRONMENTAL - SEACOAST	Expense	Active
102060005890100	DIST OPER RENTS-SEA	Expense	Active
102060005900000	DIST MAINT GENERAL SUPERVISION-SEA	Expense	Active
102060005900001	DIST MAINT GEN SUPERVISION SUBSTATION	Expense	Active
102060005900100	UNPROD TIME/SICKNESS-SEA	Expense	Active
102060005900101	STATION UNPROD TIME SICK	Expense	Active
102060005900200	UNPROD TIME/WEATHER-SEA	Expense	Active
102060005900201	STATION UNPROD TIME WEATHER	Expense	Active
102060005900300	UNPROD TIME/HOLIDAY-SEA	Expense	Active
102060005900301	STATION UNPRODUCTIVE TIME HOLIDAY	Expense	Active

102060005900400	UNPROD TIME/VACATION-SEA	Expense	Active
102060005900401	STATION UNPROD TIME VACATION	Expense	Active
102060005900500	UNPROD TIME/OTHER-SEA	Expense	Active
102060005900501	STATION UNPROD TIME OTHER	Expense	Active
102060005910000	DIST MAINT STRUCTURE SERV CTR-SEA	Expense	Active
102060005920100	DIST MAINT STAT EQUIP UNSCHED-SEA	Expense	Active
102060005920200	DIST MAINT STAT EQUIP ANNUAL-SEA	Expense	Active
102060005920300	DIST MAINT STAT EQUIP CYCLE-SEA	Expense	Active
102060005920400	DIST MAINT STAT EQUIP SCADA-SEA	Expense	Active
102060005920500	DIST MAINT MOBILE SUB-SEA	Expense	Active
102060005930100	DIST MAINT UNSCHEDULED-SEA	Expense	Active
102060005930200	DIST MAINT SCHEDULED-SEA	Expense	Active
102060005930201	RELIABILITY INSPECTIONS	Expense	Active
102060005930202	RELIABILITY MAINTENANCE & REPAIRS	Expense	Active
102060005930500	DIST STORM TROUBLE-SEA	Expense	Active
102060005940000	DIST MAINT U/G LINES-SEA	Expense	Active
102060005950000	DIST MAINT TRANSFORMER REPAIR-SEA	Expense	Active
102060005960000	DIST MAINT ST LIGHT REPAIR-SEA	Expense	Active
102060005970000	DIST MAINT METER REPAIR-SEA	Expense	Active
102060005970100	AMI COMMUNICATIONS AND TROUBLESHOOTING (SUB STATION)	Expense	Active
102060005980000	DIST MAINT MISC EQUIPMENT-SEA	Expense	Active
102060005980200	DIST MAINT COMMUNICATION EQUIP-SEA	Expense	Active
102060005980300	DIST MAINT AMI SYSTEM - SEA	Expense	Active
102060009020000	CUST ACCTS METER READ EXP-SEA	Expense	Active
102060009030000	CREDIT DISCONNECTION-SEA	Expense	Active
102060009030401	POSTAGE-LOCAL-SEA	Expense	Active
102060009090000	INFORMATION INSTRUCTION-SEA	Expense	Active
102060009100000	CUSTOMER SERVICE MISC-SEA	Expense	Active
102060009200000	A&G SALARIES-SEA	Expense	Active
102060009210100	ADMIN OFFICE & TEL EXP-SEA	Expense	Active
102060009210200	GEN OFFICE SUPPLIES-SEA	Expense	Active
102060009211700	Telephone Services - Service Center-SEA	Expense	Active
102060009211800	Telephone Services - All Others-SEA	Expense	Active
102060009213000	DUES TO ORGANIZATIONS	Expense	Active
102060009230000	OS LEGAL-LOCAL-SEA	Expense	Active
102060009250100	INJURIES & DAMAGES SAFETY-SEA	Expense	Active
102060009260600	Employee Benefits Other-Sea	Expense	Active
102060009300100	GENERAL ADVERTISING-SEA	Expense	Active
102060009301000	MISC EXP - PANDEMIC COSTS - SEACOAST	Expense	Active
102060009310000	RENTS-SEA	Expense	Active
102060009350100	MAINTENANCE - GENERAL STRUCTURES-SEA	Expense	Active
102060009350102	MAINT OF GEN STRUCT - BUILD ENVIRONMENTAL	Expense	Active
102500001310100	CASH -SUPPLIER - FLEET #7483	Assets	Active
102500001420100	EXTERNAL SUPPLIER - A/R - NEW ENERGY	Assets	Active
102500001420300	EXTERNAL SUPPLIER - A/R - ISO NE	Assets	Active
102500001420400	EXTERNAL SUPPLIER - A/R - TRANSCANADA	Assets	Active
102500001420500	EXTERNAL SUPPLIER - A/R - WPS ENERGY	Assets	Active
102500001420600	EXTERNAL SUPPLIER - A/R - HESS	Assets	Active
102500001420700	EXTERNAL SUPPLIER - A/R - CON ED	Assets	Active

102500001420800	EXTERNAL SUPPLIER - A/R - GEXA	Assets	Active
102500001420900	EXTERNAL SUPPLIER - A/R - GLACIAL ENERGY	Assets	Active
102500001421000	EXTERNAL SUPPLIER - SOUTH JERSEY	Assets	Active
102500001422500	EXT SUPPLIER AR - PEOPLES POWER	Assets	Active
102500001422600	EXT SUPPLIER - AR THINK ENERGY	Assets	Active
102500001422700	EXT SUPPLIER - AR NOBLE AMERICAS ENERGY SOLUTIONS	Assets	Active
102500001422800	EXT SUPPLIER - AR TEXAS RETAIL ENERGY	Assets	Active
102500001422900	EXT SUPPLIER - AR FAIRPOINT ENERGY	Assets	Active
102500001423000	EXT SUPPLIER - AR ELECTRICITY NH	Assets	Active
102500001423100	EXT SUPPLIER - AR - PNE	Assets	Active
102500001423400	EXT SUPPLIER - AR TOWN SQUARE ENERGY	Assets	Active
102500001423600	EXT SUPPLIER - AR NORTH AMERICAN PWR - UIT	Assets	Active
102500001423700	EXT SUPPLIER - FIRST POINT POWER-FPP	Assets	Active
102500001423800	EXT SUPPLIER - AR REP ENERGY	Assets	Active
102500001423900	EXT SUPPLIER - AR - UNION ATLANTIC ELECTRICITY	Assets	Active
102500001424000	EXT SUPPLIER - AR - ETHICAL ELECTRIC INC	Assets	Active
102500001424100	EXT SUPPLIER - AR - AMBIT NORTHEAST, LLC	Assets	Active
102500001424200	EXT SUPPLIER - AR - AGERA ENERGY	Assets	Active
102500001424300	EXT SUPPLIER - AR - GDF SUEZ	Assets	Active
102500001424400	EXT SUPPLIER - AR -DIRECT ENERGY BUSINESS	Assets	Active
102500001424500	EXT SUPPLIER - AR - VIRIDIAN ENERGY	Assets	Active
102500001424600	EXT SUPPLIER - AR - EVERYDAY ENERGY	Assets	Active
102500001424700	EXT SUPPLIER - AR - NORDIC ENERGY	Assets	Active
102500001424800	EXT SUPPLIER - AR - EDF ENERGY SERVICES	Assets	Active
102500001424900	EXT SUPPLIER - AR - CLEARVIEW ELECTRIC	Assets	Active
102500001425000	EXT SUPPLIER - AR - CONSTELLATION NEWENERGY C&I INC	Assets	Active
102500001425100	EXT SUPPLIER - AR - CHAMPION ENERGY SERVICES, LLC	Assets	Active
102500001425200	EXT SUPPLIER - AR - CONSTELLATION NEWENERGY (MASS MKT)	Assets	Active
102500001425300	EXT SUPPLIER - AR - SMARTENERGY HOLDINGS	Assets	Active
102500001425400	EXT SUPPLIER - AR - SUMMER ENERGY NORTHEAST	Assets	Active
102500001425500	EXT SUPPLIER - AR - MP2 Energy NE LLC	Assets	Active
102500002320102	EXTERNAL SUPPLIER -REVENUE-NEW ENERGY	Liability	Active
102500002320202	EXTERNAL SUPPLIER -REVENUE-SELECT	Liability	Active
102500002320302	EXTERNAL SUPPLIER -REVENUE-ISO NE	Liability	Active
102500002320402	EXTERNAL SUPPLIER -REVENUE-TRANSCANADA	Liability	Active
102500002320502	EXTERNAL SUPPLIER -REVENUE-WPS ENERGY	Liability	Active
102500002320602	EXTERNAL SUPPLIER -REVENUE-HESS	Liability	Active
102500002320702	EXTERNAL SUPPLIER -REVENUE-CON ED	Liability	Active
102500002320802	EXTERNAL SUPPLIER -REVENUE-GEXA	Liability	Active
102500002320902	EXTERNAL SUPPLIER -REVENUE-GLACIAL ENERGY	Liability	Active
102500002321002	EXTERNAL SUPPLIER -REVENUE-SOUTH JERSEY	Liability	Active
102500002322502	EXTERNAL SUPPLIER -REVENUE-PEOPLES POWER	Liability	Active
102500002322602	EXTERNAL SUPPLIER -REVENUE-THINK ENERGY	Liability	Active
102500002322702	EXTERNAL SUPPLIER -REVENUE-NOBLE AMERICAS ENERGY SOLUTIONS	Liability	Active
102500002322802	EXTERNAL SUPPLIER -REVENUE-TEXAS RETAIL ENERGY	Liability	Active
102500002322902	EXTERNAL SUPPLIER -REVENUE-FAIRPOINT ENERGY	Liability	Active
102500002323002	EXTERNAL SUPPLIER -REVENUE-ELECTRICITY NH	Liability	Active
102500002323102	EXTERNAL SUPPLIER -REVENUE-PNE	Liability	Active
102500002323402	EXTERNAL SUPPLIER -REVENUE-TOWN SQUARE ENERGY	Liability	Active

102500002323602	EXTERNAL SUPPLIER -REV-NORTH AMERICAN PWR-UIT	Liability	Active
102500002323702	EXTERNAL SUPPLIER -REV-FIRST POINT POWER-FPP	Liability	Active
102500002323802	EXTERNAL SUPPLIER -REV-REP ENERGY	Liability	Active
102500002323902	EXTERNAL SUPPLIER -REVENUE-UNION ATLANTIC ELECTRICITY	Liability	Active
102500002324002	EXTERNAL SUPPLIER -REVENUE-ETHICAL ELECTRIC INC	Liability	Active
102500002324102	EXTERNAL SUPPLIER -REVENUE- AMBIT NORTHEAST, LLC	Liability	Active
102500002324202	EXT SUPPLIER -REVENUE-AGERA ENERGY	Liability	Active
102500002324302	EXT SUPPLIER - REVENUE - GDF SUES	Liability	Active
102500002324402	EXT SUPPLIER - REVENUE - DIRECT ENERGY BUSINESS	Liability	Active
102500002324502	EXT SUPPLIER - REVENUE - VIRIDIAN ENERGY	Liability	Active
102500002324602	EXT SUPPLIER - REVENUE - EVERYDAY ENERGY	Liability	Active
102500002324702	EXT SUPPLIER - REVENUE - NORDIC ENERGY	Liability	Active
102500002324802	EXT SUPPLIER - REVENUE - EDF ENERGY SERVICES	Liability	Active
102500002324902	EXT SUPPLIER - REVENUE - CLEARVIEW ELECTRIC	Liability	Active
102500002325002	EXT SUPPLIER - REVENUE - CONSTELLATION NEWENERGY C&I INC	Liability	Active
102500002325102	EXT SUPPLIER - REVENUE - CHAMPION ENERGY SERVICES, LLC	Liability	Active
102500002325202	EXT SUPPLIER - REV - CONSTELLATION NEWENERGY (MASS MKTS)	Liability	Active
102500002325302	EXT SUPPLIER - REV - SMARTENERGY HOLDINGS	Liability	Active
102500002325402	EXT SUPPLIER - REV - SUMMER ENERGY NORTHEAST	Liability	Active
102500002325502	EXT SUPPLIER - REVENUE - MP2 Energy NE LLC	Liability	Active
102702504510000	WATER HEATER RENTAL REV - GAS	Revenue	Active
102702504510001	WATER HEATER RENTAL REV - ELECTRIC	Revenue	Active
102702509040000	UNCOLLECTIBLE ACCOUNTS-WATER HEATER PROGRAM	Expense	Active
102702509230600	USC EXPS - WATER HEATER PROGRAM-GAS	Expense	Active
102702509300100	ADVERTISING EXP-GENERAL- WATER HEATER PROGRAM-GAS	Expense	Active
102702509300101	ADVERTISING EXP-GENERAL- WATER HEATER PROGRAM-ELECT	Expense	Active
102702509300200	ADVERTISING EXP-CREATIVE- WATER HEATER PROGRAM-GAS	Expense	Active
102702509300300	ADVERTISING EXP-PRODUCTION- WATER HEATER PROGRAM-GAS	Expense	Active
102702509300301	ADVERTISING EXP-PRODUCTION- WATER HEATER PROGRAM-ELEC	Expense	Active
102802004261400	MARKET DEVELOPMENT - GENERAL	Expense	Active
102802004261500	VISIBILITY	Expense	Active
102802009233000	MARKET DEVELOPMENT - GENERAL	Expense	Active
102829004261300	ADVERTISING	Expense	Active
102829004261400	MARKET DEVELOPMENT - GENERAL	Expense	Active
102829004261500	VISIBILITY	Expense	Active
102829009233000	MARKET DEVELOPMENT - GENERAL	Expense	Active
102829009233203	FIELD OPERATIONS/ACCOUNT MGMT	Expense	Active
102829009233303	MKT DEVEL/PROJECT MANAGEMENT	Expense	Active
102901204400000	Elec Rev Residential - Franchise Tax	Revenue	Active
102901214400000	Elec Revenue-D-System Benefit Chg-EE	Revenue	Active
102901214403000	ELEC REVENUE - D - System Benefit Chg - EE - Ext Sup	Revenue	Active
102901214420100	Elec Revenue-G2-System Benefit Chg-EE	Revenue	Active
102901214420200	Elec Revenue-G1-System Benefit Chg-EE	Revenue	Active
102901214423100	ELEC REVENUE - G2 - SBC - EE - Ext Sup	Revenue	Active
102901214423200	ELEC REVENUE - G1 System Benefit Chg - EE - Ext Sup	Revenue	Active
102901214440000	Elec Revenue-OL-Sys Ben Chrg EE	Revenue	Active
102901214440100	Elec Rev. Unmetered Sales - Sys Ben Chrg EE	Revenue	Active
102901214443000	ELEC REVENUE - OL - Sys Ben Chrg EE - Ext Sup	Revenue	Active
102901214443100	ELEC REV UNMETERED SALES - Sys Ben Chrg EE - Ext Sup	Revenue	Active

102901214450100	Elec Revenue-Pub Auth-G2-Sys Ben Chg-EE	Revenue	Active
102901214450200	Elec Revenue-Pub Auth-G1-Sys Ben Chg-EE	Revenue	Active
102901214453100	ELEC REVENUE- Pub Auth- G2 - System Benefit Chg - EE Ext Sup	Revenue	Active
102901214453200	ELEC REV - Pub Auth - G1 - Sys Benefit Chg - EE- Ext Sup	Revenue	Active
102901214490100	ACC REV ON NH EE RES NON LOW INC	Revenue	Active
102901214490200	ACC REV ON NH EE RES LOW INC	Revenue	Active
102901214490300	ACC REV ON NH C & I	Revenue	Active
102901224400001	ELEC REV RES - LI-EAP DISCOUNT	Revenue	Active
102901224400002	ELEC REVENUE - D - LI-EAP CHARGE	Revenue	Active
102901224400003	ELEC REVENUE - LI-EAP WRITE OFFS	Revenue	Active
102901224403001	ELEC REVENUE RESIDENTIAL - LI-EAP Discount - Ext Sup	Revenue	Active
102901224403002	ELEC REVENUE - D - LI-EAP CHARGE - Ext Sup	Revenue	Active
102901224420100	ELEC REVENUE - G2 - LI-EAP CHARGE	Revenue	Active
102901224420200	ELEC REVENUE - G1 - LI-EAP CHARGE	Revenue	Active
102901224423100	ELEC REVENUE - G2 - LI-EAP CHARGE - Ext Sup	Revenue	Active
102901224423200	ELEC REVENUE - G1 - LI-EAP CHARGE - Ext Sup	Revenue	Active
102901224440000	ELEC REVENUE - OL - LI-EAP CHARGE	Revenue	Active
102901224440100	ELEC REVENUE-UNMETERED-LI-EAP CHG	Revenue	Active
102901224443000	ELEC REVENUE - OL - LI-EAP CHARGE - Ext Sup	Revenue	Active
102901224443100	ELEC REVENUE- Unmetered -LI-EAP CHARGE- Ext Sup	Revenue	Active
102901224450100	ELEC REVENUE-PUB AUTH-G2-LI-EAP CHG	Revenue	Active
102901224450200	ELEC REVENUE-PUB AUTH-G1-LI-EAP CHG	Revenue	Active
102901224453100	ELEC REVENUE- Pub Auth- G2 - LI-EAP CHARGE - Ext Sup	Revenue	Active
102901224453200	ELEC REV - Pub Auth - G1 - LI-EAP CHARGE - Ext Sup	Revenue	Active
102901224490000	ACC REV ON LIEAP OFFSET	Revenue	Active
102901229090100	NEIGHBOR HELPING NEIGHBOR-EAP	Expense	Active
102901229230000	NH LIEAP COSTS	Expense	Active
102901229230300	NH LIEAP ADMIN PRINTING/MARKETING COSTS	Expense	Active
102901229280300	REG COMM EXP - LEGAL - LIEAP	Expense	Active
102901234490000	ACC REV ON COGENERATION - QF	Revenue	Active
102901244400000	ELEC REVENUE - D - SBC-LBR	Revenue	Active
102901244403000	ELEC REVENUE - D - SBC-LBR - EXT SUP	Revenue	Active
102901244420100	ELEC REVENUE - G2-SBC-LBR	Revenue	Active
102901244420200	ELEC REVENUE - G1-SBC-LBR	Revenue	Active
102901244423100	ELEC REVENUE - G2-SBC-LBR-EXT SUP	Revenue	Active
102901244423200	ELEC REVENUE - G1-SBC-LBR-EXT SUP	Revenue	Active
102901244440000	ELEC REVENUE - OL-SBC-LBR	Revenue	Active
102901244440100	ELEC REVENUE - UNMETERED-SBC-LBR	Revenue	Active
102901244443000	ELEC REVENUE - OL - SBC-LBR - EXT SUP	Revenue	Active
102901244443100	ELEC REVENUE - UNMETERED - SBC-LBR - EXT SUP	Revenue	Active
102901244450100	ELEC REVENUE - PUB AUTH-G2-SBC-LBR	Revenue	Active
102901244450200	ELEC REVENUE - PUB AUTH-G1-SBC-LBR	Revenue	Active
102901244453100	ELEC REVENUE - PUB AUTH-G2-SBC-LBR-EXT SUP	Revenue	Active
102901244453200	ELEC REVENUE - PUB AUTH-G1-SBC-LBR-EXT SUP	Revenue	Active
102901244490000	ACC REV ON SBC-LBR	Revenue	Active
102901324400000	Elec Revenue-D-External Delivery	Revenue	Active
102901324400010	EL REV EDC NET METERING - D	Revenue	Active
102901324403000	ELEC REVENUE - D - External Delivery - Ext Sup	Revenue	Active
102901324403010	EL REV EDC NET METERING - D - EXT SUP	Revenue	Active

102901324420100	Elec Revenue-G2-External Delivery	Revenue	Active
102901324420110	EL REV EDC NET METERING - G2	Revenue	Active
102901324420200	Elec Revenue-G1-External Delivery	Revenue	Active
102901324420210	EL REV EDC NET METERING - G1	Revenue	Active
102901324423100	ELEC REVENUE - G2 - External Delivery - Ext Sup	Revenue	Active
102901324423110	EL REV EDC NET METERING - G2 - EXT SUP	Revenue	Active
102901324423200	ELEC REVENUE - G1 - External Delivery - Ext Sup	Revenue	Active
102901324423210	EL REV EDC NET METERING - G1 - EXT SUP	Revenue	Active
102901324440000	Elec Revenue-OL-External Delivery	Revenue	Active
102901324440100	Elec Revenue-Unmetered-External Delivery	Revenue	Active
102901324443000	ELEC REVENUE - OL - External Delivery - Ext Sup	Revenue	Active
102901324443100	ELEC REVENUE- Unmetered - External Delivery - Ext Sup	Revenue	Active
102901324450100	Elec Revenue-Pub Auth-G2-External Delivery	Revenue	Active
102901324450200	Elec Revenue-Pub Auth-G1-External Delivery	Revenue	Active
102901324453100	ELEC REVENUE- Pub Auth- G2 - External Delivery - Ext Sup	Revenue	Active
102901324453200	ELEC REV - Pub Auth - G1 - External Delivery - Ext Sup	Revenue	Active
102901324490000	ACC REV ON EXTERNAL DELIVERY	Revenue	Active
102901325550010	EDC - NET METERING CREDIT - D	Expense	Active
102901325550110	EDC - NET METERING CREDIT - G2	Expense	Active
102901325550210	EDC - NET METERING CREDIT - G1	Expense	Active
102901329280100	PUC REG COMM ASSESSMENT AMORT - EDC	Expense	Active
102901329280101	TRANS BASED ASSESS/FEES - EDC	Expense	Active
102901329280300	REG COMM EXP - EDC	Expense	Active
102901329280301	REG COMM EXP - LEGAL - EDC	Expense	Active
102901334400000	Elec Revenue-D-Stranded Cost	Revenue	Active
102901334403000	ELEC REVENUE - D - Stranded Cost - Ext Sup	Revenue	Active
102901334420100	Elec Revenue-G2-Stranded Cost	Revenue	Active
102901334420200	Elec Revenue-G1-Stranded Cost	Revenue	Active
102901334423100	ELEC REVENUE - G2 - Stranded Cost - Ext Sup	Revenue	Active
102901334423200	ELEC REVENUE - G1 - Stranded Cost - Ext Sup	Revenue	Active
102901334440000	Elec Revenue-OL-Stranded Cost	Revenue	Active
102901334440100	Elec Revenue-Unmetered-Stranded Cost	Revenue	Active
102901334443000	ELEC REVENUE - OL - Stranded Cost - Ext Sup	Revenue	Active
102901334443100	ELEC REVENUE- Unmetered - Stranded Cost- Ext Sup	Revenue	Active
102901334450100	Elec Revenue-Pub Auth-G2-Stranded Cost	Revenue	Active
102901334450200	Elec Revenue-Pub Auth-G1-Stranded Cost	Revenue	Active
102901334453100	ELEC REVENUE- Pub Auth- G2 - Stranded Cost - Ext Sup	Revenue	Active
102901334453200	ELEC REV - Pub Auth - G1 - Stranded Cost - Ext Sup	Revenue	Active
102901334490000	ACC REV ON STRANDED COSTS	Revenue	Active
102901364400000	Elec Revenue-D-Power Supply	Revenue	Active
102901364400020	Elec Revenue-D-Power Supply Variable	Revenue	Active
102901364420100	Elec Revenue-G2- Power Supply	Revenue	Active
102901364420120	Elec Revenue-G2-Power Supply Variable	Revenue	Active
102901364440000	ELEC REVENUE - OL - Power Supply	Revenue	Active
102901364440020	ELEC REVENUE - OL - Power Supply Variable	Revenue	Active
102901364440100	ELEC REVENUE - Unmetered - Power Supply	Revenue	Active
102901364440120	ELEC REVENUE - Unmetered - Power Supply Variable	Revenue	Active
102901364450100	Elec Revenue-Pub Auth-G2-Power Supply	Revenue	Active
102901364450120	Elec Revenue-Pub Auth-G2-Power Supply Variable	Revenue	Active

102901364490000	ACC REV ON POWER SUPPLY-NON-G1	Revenue	Active
102901369280100	REG COMM - PUC ASSESSMENT - PS NONG1	Expense	Active
102901369300099	PS ADMIN SERVICE COST - NON G1	Expense	Active
102901374420220	ELEC REV -G1-POWER SUPPLY VARIABLE	Revenue	Active
102901374450200	LG MUN - POWER SUPPLY	Revenue	Active
102901374450220	LG MUN - POWER SUPPLY - VARIABLE	Revenue	Active
102901374490000	ACC REV ON POWER SUPPLY -G1	Revenue	Active
102901379280100	REG COMM - PUC ASSESSMENT - PS G1	Expense	Active
102901379300099	PS ADMIN SERVICE COST - G1	Expense	Active
102901424400000	ELEC REVENUE-D-RPS	Revenue	Active
102901424420100	ELEC REVENUE-G2-RPS	Revenue	Active
102901424440000	ELEC REVENUE-OL-RPS	Revenue	Active
102901424440100	ELEC REVENUE-UNMETERED-RPS	Revenue	Active
102901424450100	ELEC REVENUE-PUB AUTH-G2-RPS	Revenue	Active
102901424490000	ACC REV ON RENEW PORT STD COSTS-NON-G1	Revenue	Active
102901434420200	ELEC REVENUE-G1-RPS	Revenue	Active
102901434450200	LG MUN G1 DEFAULT SVC-RPS	Revenue	Active
102901434490000	ACC REV ON RENEW PORT STD COSTS-G1	Revenue	Active
102901444490100	ACC REV ON RGGI RES NON LOW INC	Revenue	Active
102901444490200	ACC REV ON RGGI RES LOW INC	Revenue	Active
102901444490300	ACC REV ON RGGI RES C & I	Revenue	Active
102901454400000	ELEC REVENUE-D-RSO	Revenue	Active
102901454420100	ELEC REVENUE-G2-RSO	Revenue	Active
102901454450100	ELEC REVENUE-PUB AUTH-G2-RSO	Revenue	Active
102901454490000	ELEC REVENUE-RSO	Revenue	Active
102901474400000	ELEC REV RES-STORM RECOVERY ADJ	Revenue	Active
102901474403000	ELEC REV RES-STORM RECOVERY ADJ-EXT SUP	Revenue	Active
102901474420100	ELEC REV REG GEN-STORM RECOVERY ADJ	Revenue	Active
102901474420200	ELEC REV LARGE GEN-STORM RECOVERY ADJ	Revenue	Active
102901474423100	ELEC REV REG GEN-STORM RECOVERY ADJ-EXT SUP	Revenue	Active
102901474423200	ELEC REV LARGE GEN-STORM RECOVERY ADJ-EXT SUP	Revenue	Active
102901474440000	ELEC REV PUB ST LTG-STORM RECOVERY ADJ	Revenue	Active
102901474440100	ELEC REV UNMETERED SALES-STORM RECOVERY ADJ	Revenue	Active
102901474443000	ELEC REV PUB ST LTG-STORM RECOVERY ADJ-EXT SUP	Revenue	Active
102901474443100	ELEC REV UNMETERED SALES-STORM RECOVERY ADJ-EXT SUP	Revenue	Active
102901474450100	MUNICIPAL REG GEN-STORM RECOVERY ADJ	Revenue	Active
102901474450200	MUNICIPAL LARGE GEN-STORM RECOVERY ADJ	Revenue	Active
102901474453100	MUNICIPAL REG GEN-STORM RECOVERY ADJ-EXT SUP	Revenue	Active
102901474453200	MUNICIPAL LARGE GEN-STORM RECOVERY ADJ-EXT SUP	Revenue	Active
102901484490100	ACC REV ON EEBB RESIDENTIAL	Revenue	Active
102902214560000	OTHER ELEC REVENUE-GRANT FUNDING-TOTAL	Revenue	Active
102902214562000	OTHER ELECTRIC REVENUE-GRANT FUNDING - R	Revenue	Active
102902214562100	OTHER ELECTRIC REVENUE-GRANT FUNDING - RLI	Revenue	Active
102902214562200	OTHER ELECTRIC REVENUE-GRANT FUNDING - CI	Revenue	Active
102902214568000	OTHER ELECTRIC REVENUE - ISO ODR	Revenue	Active
102902219080000	ELEC GENERAL PLAN/ADMIN - ALL INT	Expense	Active
102902219080004	ELEC GENERAL EVALUATION - ALL INT	Expense	Active
102902219080005	ELEC GENERAL EVALUATION - ALL EXT	Expense	Active
102902219080020	ELECTRIC GENERAL MKTING - ALL INT	Expense	Active

102902219080021	ELEC GENERAL MARKETING - ALL EXT	Expense	Active
102902219080023	ELEC GENERAL PLANNING&ADMIN/LEGAL - ALL EXT	Expense	Active
102902219080024	ELEC GENERAL PLAN/ADMIN - RES INT	Expense	Active
102902219080025	ELEC GENERAL PLAN/ADMIN - C&I INT	Expense	Active
102902219080029	ELEC GENERAL IMPLSVC/STAT - ALL INT	Expense	Active
102902444560001	LOAN PAYBACK - RGGI - RES	Revenue	Active
102902444560002	LOAN WRITEOFF- RGGI - RES	Revenue	Active
102902444560003	LOAN WRITEOFF RECOVERY- RGGI - RES	Revenue	Active
102902444560101	LOAN PAYBACK - RGGI - LI	Revenue	Active
102902444560102	LOAN WRITEOFF- RGGI - LI	Revenue	Active
102902444560103	LOAN WRITEOFF RECOVERY- RGGI - LI	Revenue	Active
102902444560201	LOAN PAYBACK - RGGI - CI	Revenue	Active
102902444560202	LOAN WRITEOFF- RGGI - CI	Revenue	Active
102902444560203	LOAN WRITEOFF RECOVERY- RGGI - CI	Revenue	Active
102902444562000	OTHER ELECTRIC REVENUE-GRANT FUNDING - R	Revenue	Active
102902444562100	OTHER ELECTRIC REVENUE-GRANT FUNDING - RLI	Revenue	Active
102902444562200	OTHER ELECTRIC REVENUE-GRANT FUNDING - CI	Revenue	Active
102902449082610	Res RGGI HPwES ModInc ImplSvcs/STAT - Int	Expense	Active
102902449082613	Res RGGI HPwES ModInc Plan/Admin - Int	Expense	Active
102902449082614	Res RGGI HPwES ModInc Plan/Admin - Ext	Expense	Active
102902449082620	Res RGGI HPwES ModInc Marketing - Int	Expense	Active
102902449082621	Res RGGI HPwES ModInc Marketing - Ext	Expense	Active
102902449082630	Res RGGI HPwES ModInc Evaluation - Int	Expense	Active
102902449082631	Res RGGI HPwES ModInc Evaluation - Ext	Expense	Active
102902449082640	Res RGGI HPwES ModInc Prod Rebates	Expense	Active
102902449082641	Res RGGI HPwES ModInc ImplSvcs/STAT - Ext	Expense	Active
102902449084312	C&I RGGI RLF IMPLSVC/STAT - INT	Expense	Active
102902449084313	C&I RGGI RLF IMPLSVC/STAT - EXT	Expense	Active
102902449084314	C&I RGGI RLF LOAN BUYDOWN	Expense	Active
102902449084320	RES RGGI RLF IMPLSVC/STAT - INT	Expense	Active
102902449084321	RES RGGI RLF IMPLSVC/STAT - EXT	Expense	Active
102902449084322	RES RGGI RLF LOAN BUYDOWN	Expense	Active
102902449085010	C&I RGGI RETAIL PROD IMPLSVCS/STAT - INT	Expense	Active
102902449085013	C&I RGGI RETAIL PROD PLAN/ADMIN - INT	Expense	Active
102902449085014	C&I RGGI RETAIL PROD PLAN/ADMIN - EXT	Expense	Active
102902449085020	C&I RGGI RETAIL PROD MARKETING - INT	Expense	Active
102902449085021	C&I RGGI RETAIL PROD MARKETING - EXT	Expense	Active
102902449085030	C&I RGGI RETAIL PROD EVALUATION - INT	Expense	Active
102902449085031	C&I RGGI RETAIL PROD EVALUATION - EXT	Expense	Active
102902449085040	C&I RGGI RETAIL PROD REBATES	Expense	Active
102902449085041	C&I RGGI RETAIL PROD IMPLSVCS/STAT - EXT	Expense	Active
102902449085210	C&I RGGI LG BUS IMPLSVCS/STAT - INT	Expense	Active
102902449085213	C&I RGGI LG BUS PROD PLAN/ADMIN - INT	Expense	Active
102902449085214	C&I RGGI LG BUS PROD PLAN/ADMIN - EXT	Expense	Active
102902449085220	C&I RGGI LG BUS MARKETING - INT	Expense	Active
102902449085221	C&I RGGI LG BUS MARKETING - EXT	Expense	Active
102902449085230	C&I RGGI LG BUS EVALUATION - INT	Expense	Active
102902449085231	C&I RGGI LG BUS EVALUATION - EXT	Expense	Active
102902449085240	C&I RGGI LG BUS PROD REBATES	Expense	Active

102902449085241	C&I RGGI LG BUS IMPLSVCS/STAT - EXT	Expense	Active
102902484560001	LOAN PAYBACK-EEBB-RES	Revenue	Active
102902484560002	LOAN WRITEOFF-EEBB-RES	Revenue	Active
102902484560003	LOAN WRITEOFF RECOVERY-EEBB-RES	Revenue	Active
102902484562000	EEBB - GRANT FUNDING_REIMBURSEMENT - CDFA	Revenue	Active
102902509080610	Res Energy Opt Pilot ImplSvcs/STAT - Int	Expense	Active
102902509080613	Res Energy Opt Pilot Plan/Admin - Int	Expense	Active
102902509080614	Res Energy Opt Pilot Plan/Admin - Ext	Expense	Active
102902509080620	Res Energy Opt Pilot Marketing - Int	Expense	Active
102902509080621	Res Energy Opt Pilot Marketing - Ext	Expense	Active
102902509080630	Res Energy Opt Pilot Evaluation - Int	Expense	Active
102902509080631	Res Energy Opt Pilot Evaluation - Ext	Expense	Active
102902509080640	Res Energy Opt Pilot Rebates	Expense	Active
102902509080641	Res Energy Opt Pilot ImplSvcs/STAT - Ext	Expense	Active
102902509082010	Res Active Demand ImplSvcs/STAT - Int	Expense	Active
102902509082013	Res Active Demand Plan/Admin - Int	Expense	Active
102902509082014	Res Active Demand Plan/Admin - Ext	Expense	Active
102902509082020	Res Active Demand Marketing - Int	Expense	Active
102902509082021	Res Active Demand Marketing - Ext	Expense	Active
102902509082030	Res Active Demand Evaluation - Int	Expense	Active
102902509082031	Res Active Demand Evaluation - Ext	Expense	Active
102902509082040	Res Active Demand Rebates	Expense	Active
102902509082041	Res Active Demand ImplSvcs/STAT - Ext	Expense	Active
102902509082610	RES HPWES IMPLSVCS/STAT - INT	Expense	Active
102902509082613	RES HPWES PLAN/ADMIN - INT	Expense	Active
102902509082614	RES HPWES PLAN/ADMIN - EXT	Expense	Active
102902509082620	RES HPWES MARKETING - INT	Expense	Active
102902509082621	RES HPWES MARKETING - EXT	Expense	Active
102902509082630	RES HPWES EVALUATION - INT	Expense	Active
102902509082631	RES HPWES EVALUATION - EXT	Expense	Active
102902509082640	RES HPWES REBATES	Expense	Active
102902509082641	RES HPWES IMPLSVCS/STAT - EXT	Expense	Active
102902509082642	RES HPWES LOAN BUYDOWN	Expense	Active
102902509082810	RES LIGHTING IMPLSVCS/STAT - INT	Expense	Active
102902509082813	RES LIGHTING PLAN/ADMIN - INT	Expense	Active
102902509082814	RES LIGHTING PLAN/ADMIN - EXT	Expense	Active
102902509082820	RES LIGHTING MARKETING - INT	Expense	Active
102902509082821	RES LIGHTING MARKETING - EXT	Expense	Active
102902509082830	RES LIGHTING EVALUATION - INT	Expense	Active
102902509082831	RES LIGHTING EVALUATION - EXT	Expense	Active
102902509082840	RES LIGHTING REBATES	Expense	Active
102902509082841	RES LIGHTING IMPLSVCS/STAT - EXT	Expense	Active
102902509083010	RES BEHAVIOR IMPLSVCS/STAT - INT	Expense	Active
102902509083013	RES BEHAVIOR PLAN/ADMIN - INT	Expense	Active
102902509083014	RES BEHAVIOR PLAN/ADMIN - EXT	Expense	Active
102902509083020	RES BEHAVIOR MARKETING - INT	Expense	Active
102902509083021	RES BEHAVIOR MARKETING - EXT	Expense	Active
102902509083030	RES BEHAVIOR EVALUATION - INT	Expense	Active
102902509083031	RES BEHAVIOR EVALUATION - EXT	Expense	Active

102902509083040	RES BEHAVIOR REBATES	Expense	Active
102902509083041	RES BEHAVIOR IMPLSVCS/STAT - EXT	Expense	Active
102902509084010	Res HVAC/Appl ImplSvcs/STAT - Int	Expense	Active
102902509084013	Res HVAC/Appl Plan/Admin - Int	Expense	Active
102902509084014	Res HVAC/Appl Plan/Admin - Ext	Expense	Active
102902509084020	Res HVAC/Appl Marketing - Int	Expense	Active
102902509084021	Res HVAC/Appl Marketing - Ext	Expense	Active
102902509084030	Res HVAC/Appl Evaluation - Int	Expense	Active
102902509084031	Res HVAC/Appl Evaluation - Ext	Expense	Active
102902509084040	Res HVAC/Appl Rebates	Expense	Active
102902509084041	Res HVAC/Appl ImplSvcs/STAT - Ext	Expense	Active
102902509084710	Res NewHomes/Reno ImplSvcs/STAT - Int	Expense	Active
102902509084713	Res HewHomes/Reno Plan/Admin - Int	Expense	Active
102902509084714	Res HewHomes/Reno Plan/Admin - Ext	Expense	Active
102902509084720	Res HewHomes/Reno Marketing - Int	Expense	Active
102902509084721	Res HewHomes/Reno Marketing - Ext	Expense	Active
102902509084730	Res HewHomes/Reno Evaluation - Int	Expense	Active
102902509084731	Res HewHomes/Reno Evaluation - Ext	Expense	Active
102902509084740	Res HewHomes/Reno Rebates	Expense	Active
102902509084741	Res HewHomes/Reno ImplSvcs/STAT - Ext	Expense	Active
102902509084805	Res Statewide Marketing - Int	Expense	Active
102902509084811	Res Statewide Marketing - Ext	Expense	Active
102902509088001	Res ISO Eval - Internal	Expense	Active
102902509088002	RES ISO PLAN/ADMIN - EXT	Expense	Active
102902509088003	Res ISO - Ext Eval	Expense	Active
102902519084110	LI SINGLEFAM IMPLSVCS/STAT - INT	Expense	Active
102902519084113	LI SINGLEFAM PLAN/ADMIN - INT	Expense	Active
102902519084114	LI SINGLEFAM PLAN/ADMIN - EXT	Expense	Active
102902519084120	LI SINGLEFAM MARKETING - INT	Expense	Active
102902519084121	LI SINGLEFAM MARKETING - EXT	Expense	Active
102902519084130	LI SINGLEFAM EVALUATION - INT	Expense	Active
102902519084131	LI SINGLEFAM EVALUATION - EXT	Expense	Active
102902519084140	LI SINGLEFAM REBATES	Expense	Active
102902519084141	LI SINGLEFAM IMPLSVCS/STAT - EXT	Expense	Active
102902519084806	LI Statewide Marketing - Int	Expense	Active
102902519084812	LI Statewide Marketing - Ext	Expense	Active
102902529082101	C&I Edu ImplSvc/STAT - Int	Expense	Active
102902529082102	C&I Edu ImplSvc/STAT - Ext	Expense	Active
102902529082103	C&I Edu Mrkting - Ext	Expense	Active
102902529082104	C&I Edu Eval - Ext	Expense	Active
102902529082201	Res Edu ImplSvc/STAT - Int	Expense	Active
102902529082202	Res Edu ImplSvc/STAT - Ext	Expense	Active
102902529082203	Res Edu Mrkting - Ext	Expense	Active
102902529082204	Res Edu Eval - Ext	Expense	Active
102902529084807	C&I Statewide Marketing - Int	Expense	Active
102902529084813	C&I Statewide Marketing - Ext	Expense	Active
102902529085110	C&I SM BUS IMPLSVCS/STAT - INT	Expense	Active
102902529085113	C&I SM BUS PLAN/ADMIN - INT	Expense	Active
102902529085114	C&I SM BUS PLAN/ADMIN - EXT	Expense	Active

102902529085120	C&I SM BUS MARKETING - INT	Expense	Active
102902529085121	C&I SM BUS MARKETING - EXT	Expense	Active
102902529085130	C&I SM BUS EVALUATION - INT	Expense	Active
102902529085131	C&I SM BUS EVALUATION - EXT	Expense	Active
102902529085140	C&I SM BUS REBATES	Expense	Active
102902529085141	C&I SM BUS IMPLSVCS/STAT - EXT	Expense	Active
102902529085210	C&I LG BUS IMPLSVCS/STAT - INT	Expense	Active
102902529085213	C&I LG BUS PLAN/ADMIN - INT	Expense	Active
102902529085214	C&I LG BUS PLAN/ADMIN - EXT	Expense	Active
102902529085220	C&I LG BUS MARKETING - INT	Expense	Active
102902529085221	C&I LG BUS MARKETING - EXT	Expense	Active
102902529085230	C&I LG BUS EVALUATION - INT	Expense	Active
102902529085231	C&I LG BUS EVALUATION - EXT	Expense	Active
102902529085240	C&I LG BUS REBATES	Expense	Active
102902529085241	C&I LG BUS IMPLSVCS/STAT - EXT	Expense	Active
102902529085410	C&I MUNI IMPLSVCS/STAT - INT	Expense	Active
102902529085413	C&I MUNI PLAN/ADMIN - INT	Expense	Active
102902529085414	C&I MUNI PLAN/ADMIN - EXT	Expense	Active
102902529085420	C&I MUNI MARKETING - INT	Expense	Active
102902529085421	C&I MUNI MARKETING - EXT	Expense	Active
102902529085430	C&I MUNI EVALUATION - INT	Expense	Active
102902529085431	C&I MUNI EVALUATION - EXT	Expense	Active
102902529085440	C&I MUNI REBATES	Expense	Active
102902529085441	C&I MUNI IMPLSVCS/STAT - EXT	Expense	Active
102902529086510	C&I Act Demand ImplSvcs/STAT - Int	Expense	Active
102902529086521	C&I Act Demand Marketing - Ext	Expense	Active
102902529086530	C&I Act Demand Evaluation - Int	Expense	Active
102902529086531	C&I Act Demand Evaluation - Ext	Expense	Active
102902529086540	C&I Act Demand Rebates	Expense	Active
102902529086541	C&I Act Demand ImplSvcs/STAT - Ext	Expense	Active
102902529088004	C&I ISO - Internal Eval	Expense	Active
102902529088005	C&I ISO PLANNING/ADMIN - EXT	Expense	Active
102902529088006	C&I ISO - Ext Eval	Expense	Active
102908154420201	LG Gen Interrupt. CR. - Base Rev, Trans, Tranf Disc, Distrib	Revenue	Active
102908154440100	Elec Rev. Unmetered Sales - Base Rev, Trans, Tranf Disc, Dis	Revenue	Active
102908154450000	Elec Rev. Sales to Pub Auth - Base Rev, Trans, Tranf Disc,	Revenue	Active
102908154450001	Pub Auth Interruptible Credit - Base Rev, Trans, Tranf Disc	Revenue	Active
102908204420201	LG Gen Interrupt. CR.- Franchise Tax	Revenue	Active
102908204450000	Elec Rev. Sales to Pub Auth - Franchise Tax	Revenue	Active
102908204450001	Pub Auth Interruptible Credit- Franchise Tax	Revenue	Active
102908224400000	ELEC REVENUE - D - LI-EAP DISCOUNT OFFSET	Revenue	Active
102908224400008	ELEC REV RES-CUST CHG- LI-EAP DISCOUNT	Revenue	Active
102908224400009	ELEC REV RES-BLOCK 1 -LI-EAP DISCOUNT	Revenue	Active
102908224400010	ELEC REV RES-BLOCK 2 -LI-EAP DISCOUNT	Revenue	Active
102908344490001	ACC REV ON TRANSITION SERVICE-NON-G1	Revenue	Active
102910234490500	ACC REV ON COGENERATION-QF	Revenue	Active
102910324070300	RATE CASE COST AMORT - EDC	Expense	Active
102910324070301	RATE CASE COST AMORT - NET METERING - EDC	Expense	Active
102910324070302	RATE CASE COST AMORT - GRID MODERN - EDC	Expense	Active

102910324190099 EDC WORKING COST OF CAPITAL	Revenue	Active
102910324490000 ACCRUED REVENUE JE - EDC	Revenue	Active
102910324490100 ACC REV-DISPLACED DISTRIB REVENUE	Revenue	Active
102910334490000 ACCRUED REVENUE JE - SCC	Revenue	Active
102910364190099 PS WORKING COST OF CAPITAL - NON G1	Revenue	Active
102910364490000 ACCRUED REVENUE JE - PS NON G-1	Revenue	Active
102910374190099 PS WORKING COST OF CAPITAL - G1	Revenue	Active
102910374490000 ACCRUED REVENUE JE - PS G-1	Revenue	Active
102910424190099 RPS WORKING COST OF CAPITAL - NON G1	Revenue	Active
102910424490000 ACC REV ON RENEW PORT STD COSTS-NON-G1	Revenue	Active
102910434190099 RPS WORKING COST OF CAPITAL - G1	Revenue	Active
102910434490000 ACC REV ON RENEW PORT STD COSTS-G1	Revenue	Active
102910474070000 AMORTIZATION - STORM RECOVERY	Expense	Active
102912325610500 RELIABILITY PLANNING AND STANDARDS DEVELOPMENT - EDC	Expense	Active
102912329231500 OS - FERC COMPLIANCE-EDC	Expense	Active
102913234470500 COGENERATION REVENUES - QF (ENERGY)	Revenue	Active
102913234470501 COGENERATION REVENUES-QF (CAPACITY)	Revenue	Active
102913235550500 COGENERATION COSTS - QF CONCORD STEAM ENERGY	Expense	Active
102913235550501 COGENERATION COSTS - QF - CONCORD STEAM CAPACITY	Expense	Active
102913235550502 COGENERATION COSTS - QF PENACOOK FALLS LOWER ENERGY	Expense	Active
102913235550503 COGENERATION COSTS - QF PENACOOK FALLS LOWER CAPACITY	Expense	Active
102913235550600 QF - BRIAR HYDRO ASSOC	Expense	Active
102913325555500 RGGI AUCTION PROCEEDS	Expense	Active
102913325558800 ST PURCH DEMAND-UNMETERED-EDC	Expense	Active
102913325558900 ST PURCH ENERGY-UNMETERED-EDC	Expense	Active
102913325560000 DATA & INFO SERVICES-EDC	Expense	Active
102913325610400 SCHED SYS CONTROL & DISP-RTO BILLGS-EDC	Expense	Active
102913325610800 RELIAB PLANNING & STD DEV-RTO BILLGS-EDC	Expense	Active
102913325650000 THIRD PARTY TRANSMISSION-EDC	Expense	Active
102913325650001 NU WHOLESALE DISTRIBUTION - EDC	Expense	Active
102913325650100 REGIONAL TRANS & OPER ENTITIES-EDC	Expense	Active
102913325750700 MKT ADMIN MONITORING & COMP-RTO BILLGS-EDC	Expense	Active
102913329230600 UPC BILL-ADMIN SERVICE CHG-EDC	Expense	Active
102913329231100 CONSULTING OUTSIDE SERVICES - EDC	Expense	Active
102913329231200 LOAD ALLOCATION AND EDI-EDC	Expense	Active
102913329231600 RSO PROGRAM OUTSIDE SERVICES - EDC	Expense	Active
102913329280300 REG COMM EXP - LEGAL - EDC	Expense	Active
102913329280301 REG COMM EXP - LEGAL - TRANSMISSION - EDC	Expense	Active
102913335550100 UPC BILL-CONTRACT RELESE PMTS-SCC	Expense	Active
102913365550000 NON-G1-PS	Expense	Active
102913365550001 NON-G1-PS-CONSTELLATION	Expense	Active
102913365550005 NON-G1-PS-TRANS CANADA	Expense	Active
102913365550007 NON-G1-PS-CITIGROUP	Expense	Active
102913365550008 NON-G1-PS-NEXTERA ENERGY MARKETING INC.	Expense	Active
102913365550009 NON-G1-PS-PSEG ENERGY	Expense	Active
102913365550010 NON-G1-PS-DOMINION	Expense	Active
102913365550013 NON G1-PS-DTE ENERGY TRADING	Expense	Active
102913365550014 NON-G1-PS-NOBLE AMERICAS	Expense	Active
102913365550015 NON-G1-PS-HYDRO QUEBEC US	Expense	Active

102913365550016	NON-G1-PS-INTEGRYS	Expense	Active
102913365550017	NON-G1-PS-ENERGY AMERICA	Expense	Active
102913365550018	NON-G1-PS-EXELON	Expense	Active
102913365550019	NON-G1-PS-VITOL	Expense	Active
102913365551000	NON-G1 GIS COST	Expense	Active
102913365555500	RGGI AUCTION PROCEEDS - NON-G1	Expense	Active
102913369230000	O/S-LEGAL-DS-NON-G1	Expense	Active
102913369231100	CONSULTING OUTSIDE SERVICES-DS-NON-G1	Expense	Active
102913369280300	REG COMM EXP-LEGAL-DS-NON-G1	Expense	Active
102913375550000	G1-PS GENERAL	Expense	Active
102913375550001	G1-PS-CONSTELLATION	Expense	Active
102913375550008	G1-PS-NEXTERA ENERGY MARKETING INC.	Expense	Active
102913375550010	G1-PS-DOMINION	Expense	Active
102913375550011	G1-PS-HESS	Expense	Active
102913375550013	G1-PS-DTE ENERGY TRADING	Expense	Active
102913375550014	G1-PS-NOBLE AMERICAS	Expense	Active
102913375550016	G1-PS-INTEGRYS	Expense	Active
102913375550017	G1-PS-DYNEGY	Expense	Active
102913375550018	G1 - Net Metering Revenue	Expense	Active
102913375550019	G1 - PS - HQUS	Expense	Active
102913375551000	GIS COST G1	Expense	Active
102913375555500	RGGI AUCTION PROCEEDS - G1	Expense	Active
102913379230000	O/S-LEGAL-PS-G1	Expense	Active
102913379231100	CONSULTING OUTSIDE SERVICES-DS-G1	Expense	Active
102913379280300	REG COMM EXP-LEGAL-DS-G1	Expense	Active
102913425556501	TYPE 1 RPS - NON G1	Expense	Active
102913425556502	TYPE 2 RPS - NON G1	Expense	Active
102913425556503	TYPE 3 RPS - NON G1	Expense	Active
102913425556504	TYPE 4 RPS - NON G1	Expense	Active
102913435556501	TYPE 1 RPS - G1	Expense	Active
102913435556502	TYPE 2 RPS - G1	Expense	Active
102913435556503	TYPE 3 RPS - G1	Expense	Active
102913435556504	TYPE 4 RPS - G1	Expense	Active
102913455556501	TYPE 1 RPS-RSO PROGRAM	Expense	Active
102913455556502	TYPE 2 RPS-RSO PROGRAM	Expense	Active
102921369040000	PROVISION FOR DOUBTFUL ACCTS-PS-NON-G1	Expense	Active
102921369040002	BD EXP CIS G-2 NON-DIST	Expense	Active
102921369040005	BD EXP CIS D-RES-NON-DIST	Expense	Active
102921369040011	BAD DEBT EXP NON G-1-NON-DIST	Expense	Active
102921369040030	BD EXP CIS OL-NON-DIST	Expense	Active
102921369040065	BD EXP CIS SP CT-NON-DIST	Expense	Active
102921379040000	PROVISION FOR DOUBTFUL ACCTS-PS-G1	Expense	Active
102921379040001	AFDA G-1 - NON-DIST	Expense	Active
102922325610500	RELIABILITY PLANNING AND STANDARDS DEVELOPMENT - EDC	Expense	Active
102922329231500	OS - FERC COMPLIANCE-EDC	Expense	Active

(10) The utility's Securities and Exchange Commission 10K forms and 10Q forms or hyperlinks thereto, for the most recent 2 years.

Response:

Unitil Energy Systems, Inc. does not make Form 10-K or Form 10-Q filings.

(11) A detailed list of all membership fees, dues, and donations for the test year charged above the line showing the trade, technical, and professional associations and organizations and amount, and the account charged, according to the following guidelines:

a. If the utility's annual gross revenues are less than $100,000,000 all membership fees, dues and donations shall be reported; and
b. If the utility's annual gross revenues are $100,000,000 or more, all membership fees, dues and donations of $5,000 and more shall be reported;

Response:

In 2020, UES paid membership dues to one vendor who met the above criteria:

Edison Electric Institute	$50,773.56	#10.20.13.00.921.03.00

(12) The utility's most recent depreciation study if not previously filed in an adjudicative proceeding.

Response:

The Company's most recent depreciation study is filed in this proceeding. Please see the Direct Testimony of Company witness Ned W. Allis of Gannett Fleming Valuation and Rate Consultants, LLC.

(13) The utility's most recent management and financial audits if not previously filed in an adjudicative proceeding.

Response:

No management audits have been performed within the last five years.

Please see PUC 1604.01(a) – 13 Attachment 1 which is Unitil Energy Systems, Inc.'s Annual Report to Noteholders for the year ended December 31, 2020.

PUC 1604.01(a) - 13 Attachment 1

UNITIL ENERGY SYSTEMS, INC.

CERTIFICATION TO NOTEHOLDERS

I hereby certify that the accompanying Balance Sheets as of December 31, 2020 and December 31, 2019, Statements of Earnings for the years ended December 31, 2020, 2019 and 2018, Statements of Cash Flows for the years ended December 31, 2020, 2019 and 2018, and Statements of Changes in Shareholder's Equity for the years ended December 31, 2020, 2019 and 2018, were, to the best of my knowledge and belief, properly prepared and are correct.

I also certify that the accompanying calculation worksheets, pursuant to Sections 10.1 and 10.5 of the applicable Unitil Energy Systems, Inc. Bond Agreements, were, to the best of my knowledge and belief, properly prepared and are correct.

I also certify that I have reviewed the provisions of the Unitil Energy System Inc.'s Bond Purchase Agreements, and to the best of my knowledge and belief the Company was, and remains in compliance with the provisions of these Agreements and no Event of Default exists or occurred during the period of the financial statements ending December 31, 2020 and up to the date of this certification.

Daniel J. Hurstak
Controller

March 22, 2021

Unitil Energy Systems, Inc.

(a) Ratio of Funded Indebtedness to Total Capitalization

The information below is being provided in accordance with Section 10.1 (a) of the Bond Purchase Agreements for Unitil Energy Systems, Inc.'s 4.18% First Mortgage Bonds, Series Q, due November 30, 2048 and 3.58% First Mortgage Bonds, Series R, due September 15, 2040.

	(Millions) As of December 31, 2020	
Funded Indebtedness [1]	$	102.0
Total Capitalization	$	208.3
Funded Indebtedness / Total Capitalization [2]		49.0%

[1] **Funded Indebtedness is Total Capitalization less Common Stock Equity as of the balance sheet date.**

[2] **Per Section 10.1(a) of the Bond Purchase Agreements, Funded Indebtedness cannot exceed 65% of Total Capitalization.**

Unitil Energy Systems, Inc.

(a) Restrictions on Dividends

The information below is being provided in accordance with Section 10.1 (a) of the Bond Purchase Agreements for Unitil Energy Systems, Inc.'s 4.18% First Mortgage Bonds, Series Q, due November 30, 2048 and 3.58% First Mortgage Bonds, Series R, due September 15, 2040. As Section 11 (f) of the Bond Purchase Agreements contains cross-default provisions, the most restrictive calculation of the amount "Available for Dividends" is being provided here.

		(Millions) As of December 31, 2020
Stated Amount	$	70.0
Add: Equity Contribution - 2020		7.7
Add: Net Income - 2020		8.1
Subtotal	**$**	**85.8**
Less: Dividends Declared / Paid - 2020		6.8
Available for Dividends [1]	**$**	**79.0**

[1] Per Section 10.5 of the Bond Purchase Agreements, the Company may not declare or pay any dividend (other than dividends payable solely in shares of its own common stock) or make any other distributions of cash, property or assets on any shares of any class of its capital stock or apply any of its cash, property or assets (other than amounts equal to net proceeds received from the sale of common stock of the Company subsequent to the date of the Agreements) to the purchase or retirement of, or make any other distribution, through reduction of capital or otherwise, in respect of any shares of its capital stock in excess of the amount "Available for Dividends".

Deloitte.

Deloitte & Touche LLP
200 Berkeley Street
Boston, MA 02116-5022
USA

Tel: + 1 617 437 2000
www.deloitte.com

INDEPENDENT AUDITORS' REPORT

To the Board of Directors of
Unitil Energy Systems, Inc.
Hampton, NH

We have audited the accompanying financial statements of Unitil Energy Systems, Inc. (the "Company") (a wholly-owned subsidiary of Unitil Corporation), which comprise the balance sheets as of December 31, 2020 and 2019, and the related statements of earnings, changes in shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2020 and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Unitil Energy Systems, Inc. as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, in accordance with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

March 22, 2021

FINANCIAL STATEMENTS
AND
INDEPENDENT AUDITORS' REPORT

UNITIL ENERGY SYSTEMS, INC.
For the Period Ended December 31, 2020

UNITIL ENERGY SYSTEMS, INC.
STATEMENTS OF EARNINGS
($ in Millions)

	Year Ended December 31,		
	2020	2019	2018
Operating Revenues	**$ 158.9**	$ 161.8	$ 157.6
Operating Expenses:			
Cost of Electric Sales	**96.7**	99.9	95.2
Operation and Maintenance	**21.3**	22.9	22.4
Depreciation and Amortization	**15.9**	15.3	14.9
Taxes Other Than Income Taxes	**7.2**	6.3	6.3
Total Operating Expenses	**141.1**	144.4	138.8
Operating Income	**17.8**	17.4	18.8
Interest Expense	**5.9**	6.3	5.9
Other Expense, net	**0.8**	0.6	1.2
Income Before Income Taxes	**11.1**	10.5	11.7
Provision for Income Taxes	**3.0**	2.9	3.2
Net Income Applicable to Common Stock	**$ 8.1**	$ 7.6	$ 8.5

(The accompanying Notes are an integral part of these financial statements.)

UNITIL ENERGY SYSTEMS, INC.
BALANCE SHEETS
($ in Millions)

	December 31, 2020	2019
ASSETS:		
Current Assets:		
Cash and Cash Equivalents	$ 2.6	$ 1.5
Accounts Receivable – Net of Allowance for Doubtful Accounts of $0.6 and $0.2	18.7	16.3
Accrued Revenue	12.2	13.3
Materials and Supplies	1.4	1.4
Prepayments and Other	2.0	2.0
Total Current Assets	36.9	34.5
Utility Plant:		
Electric	403.4	363.4
Construction Work in Progress	5.1	16.0
Utility Plant	408.5	379.4
Less: Accumulated Depreciation	115.0	109.9
Net Utility Plant	293.5	269.5
Other Noncurrent Assets:		
Regulatory Assets	44.0	40.0
Operating Lease Right of Use Assets	1.7	1.4
Other Assets	1.7	1.6
Total Other Noncurrent Assets	47.4	43.0
TOTAL ASSETS	$ 377.8	$ 347.0

(The accompanying Notes are an integral part of these financial statements.)

UNITIL ENERGY SYSTEMS, INC.
BALANCE SHEETS
($ in Millions, except par value and shares data)

	December 31, 2020	2019
LIABILITIES AND CAPITALIZATION:		
Current Liabilities:		
Accounts Payable	$ **14.6**	$ 16.7
Short-Term Debt	**8.2**	13.1
Long-Term Debt, Current Portion	**3.4**	8.4
Due to Affiliates	**4.5**	5.0
Energy Supply Obligations	**3.6**	3.1
Regulatory Liabilities	**1.9**	2.0
Taxes Payable	**0.1**	2.0
Other Current Liabilities	**4.7**	4.6
Total Current Liabilities	**41.0**	54.9
Noncurrent Liabilities:		
Energy Supply Obligations	**---**	0.3
Deferred Income Taxes	**26.3**	22.5
Cost of Removal Obligations	**22.9**	21.5
Retirement Benefit Obligations	**60.8**	54.2
Regulatory Liabilities	**16.6**	16.6
Operating Leases, Less Current Portion	**1.2**	1.1
Other Noncurrent Liabilities	**0.7**	0.5
Total Noncurrent Liabilities	**128.5**	116.7
Capitalization:		
Long-term Debt, Less Current Portion	**101.8**	77.9
Stockholders' Equity:		
Common Stock, No Par Value		
Authorized - 250,000 shares		
Issued and Outstanding - 131,746 shares	**62.1**	54.4
Retained Earnings	**44.2**	42.9
Total Stockholders' Equity	**106.3**	97.3
Preferred Stock:		
Preferred Stock, Non-Redeemable, Non-Cumulative:		
6.00% Series, $100 Par Value	**0.2**	0.2
Total Stockholders' Equity	**106.5**	97.5
Total Capitalization	**208.3**	175.4
Commitments and Contingencies (Note 6)		
TOTAL LIABILITIES AND CAPITALIZATION	$ **377.8**	$ 347.0

(The accompanying Notes are an integral part of these financial statements.)

UNITIL ENERGY SYSTEMS, INC.
STATEMENTS OF CASH FLOWS
($ in Millions)

	Year Ended December 31,		
	2020	2019	2018
Operating Activities:			
Net Income	$ **8.1**	$ 7.6	$ 8.5
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:			
Depreciation and Amortization	**15.9**	15.3	14.9
Deferred Tax Provision	**3.0**	2.9	3.2
Changes in Working Capital:			
Accounts Receivable	**(2.4)**	3.0	0.7
Accrued Revenue and Energy Supply Obligations	**1.6**	(0.2)	2.6
Accounts Payable	**(2.1)**	(0.4)	1.3
Due to/from Affiliates	**(0.5)**	7.4	(0.7)
Regulatory Liabilities	**(0.1)**	(3.9)	2.2
Other Changes in Working Capital Items	**(2.1)**	1.6	(1.1)
Deferred Regulatory and Other Charges	**(2.5)**	(3.0)	(6.8)
Other, net	**2.5**	(6.7)	(1.3)
Cash Provided by Operating Activities	**21.4**	23.6	23.5
Investing Activities:			
Property, Plant, and Equipment Additions	**(35.3)**	(37.6)	(17.6)
Cash Used in Investing Activities	**(35.3)**	(37.6)	(17.6)
Financing Activities:			
(Repayment of) Proceeds from Short-Term Debt, net	**(4.9)**	13.1	(21.4)
Issuance of Long-Term Debt	**27.5**	---	30.0
Repayment of Long-Term Debt	**(8.5)**	(8.5)	(6.5)
Long-Term Debt Issuance Costs	**(0.2)**	---	---
Dividends Paid	**(6.6)**	(5.8)	(6.3)
Equity Contribution	**7.7**	12.0	---
Cash Provided by (Used in) Financing Activities	**15.0**	10.8	(4.2)
Net Increase (Decrease) in Cash and Cash Equivalents	**1.1**	(3.2)	1.7
Cash and Cash Equivalents at Beginning of Year	**1.5**	4.7	3.0
Cash and Cash Equivalents at End of Year	$ **2.6**	$ 1.5	$ 4.7
Supplemental Cash Flow Information:			
Interest Paid	$ **5.3**	$ 6.1	$ 5.7
Income Taxes Paid	$ **---**	$ ---	$ 1.3
Non-cash Investing Activity:			
Capital Expenditures Included in Accounts Payable	$ **0.3**	$ 0.1	$ 0.3
Right of Use Assets Obtained in Exchange for Lease Obligations	$ **0.3**	$ 1.4	$ ---

(The accompanying Notes are an integral part of these financial statements.)

UNITIL ENERGY SYSTEMS, INC.
STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
($ in Millions)

	Common Equity	Retained Earnings	Total
Balance at January 1, 2018	$ 42.4	$ 38.3	**$ 80.7**
Net Income		8.5	**8.5**
Dividends Declared ($40.51 Per Common Share)		(5.3)	**(5.3)**
Balance at December 31, 2018	$ 42.4	$ 41.5	**$ 83.9**
Net Income		7.6	**7.6**
Dividends Declared ($47.02 Per Common Share)		(6.2)	**(6.2)**
Equity Contribution	12.0		**12.0**
Balance at December 31, 2019	$ 54.4	$ 42.9	**$ 97.3**
Net Income		8.1	**8.1**
Dividends Declared ($52.00 Per Common Share)		(6.8)	**(6.8)**
Equity Contribution	7.7		**7.7**
Balance at December 31, 2020	$ 62.1	$ 44.2	**$ 106.3**

(The accompanying Notes are an integral part of these financial statements.)

UNITIL ENERGY SYSTEMS, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

NOTE 1: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations - Unitil Energy Systems, Inc. (Unitil Energy or Company), a wholly-owned subsidiary of Unitil Corporation (Unitil), provides electric service in New Hampshire and is subject to regulation by the New Hampshire Public Utilities Commission (NHPUC). Unitil Energy's accounting policies conform with Generally Accepted Accounting Principles in the United States of America (U.S. GAAP).

COVID-19 - In December 2019, a novel strain of coronavirus (COVID-19) emerged in Wuhan, Hubei Province, China. While initially the outbreak was largely concentrated in China and caused significant disruptions to its economy, the virus spread to several other countries and infections have been reported globally. The extent to which the coronavirus affects the Company's financial condition, results of operations, and cash flows will depend on future developments, which are highly uncertain and cannot be predicted with confidence, including the duration of the outbreak, new information which may emerge concerning the severity of the coronavirus, and the actions to contain the coronavirus or treat its effect, among others. In particular, the continued spread of the coronavirus could adversely affect the Company's business, including (i) by disrupting the Company's employees and contractors ability to provide ongoing services to Unitil Energy, (ii) by reducing customer demand for electricity, or (iii) by reducing the supply of electricity, which could have an adverse effect on the Company's financial condition, results of operations, and cash flows.

Transactions with Affiliates - In addition to its investment in Unitil Energy, Unitil Corporation has interests in two other distribution utility companies, one doing business in New Hampshire and Maine and one doing business in Massachusetts, an interstate natural gas transmission pipeline company, a service company (Unitil Service Corp.), a realty company, a power company, and a non-regulated company.

Transactions among Unitil Energy and other affiliated companies include professional and management services rendered by Unitil Service Corp. of approximately $16.0 million, $17.3 million and $16.4 million in 2020, 2019 and 2018, respectively. The Company's transactions with affiliated companies are subject to review by the NHPUC and the Federal Energy Regulatory Commission (FERC).

In 2020 and 2019, Unitil Energy received capital contributions of $7.7 million and $12.0 million, respectively, from Unitil.

Prior to May 1, 2003, Unitil Energy purchased all of its power supply from Unitil Power Corp. (Unitil Power) under the Unitil System Agreement, a FERC-regulated tariff, which provided for the recovery of all of Unitil Power's power supply-related costs on a cost pass-through basis. Effective May 1, 2003, Unitil Energy and Unitil Power amended the Unitil System Agreement, such that power sales from Unitil Power to Unitil Energy ceased, and Unitil Power sold substantially all of its entitlements under the remaining portfolio of power supply contracts. Under the amended Unitil System Agreement, Unitil Energy continues to pay contract release payments to Unitil Power for costs associated with the portfolio sale and its other ongoing power supply-related costs. As of December 31, 2020, the obligations related to these divestitures were $0.3 million and are recorded in Energy Supply Obligations on the Company's Balance Sheets with corresponding regulatory assets recorded in Accrued Revenue. Recovery of the contract release payments by Unitil Energy from its retail customers has been approved by the NHPUC.

Use of Estimates - The preparation of financial statements in conformity with U.S. GAAP requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities, and requires disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

UNITIL ENERGY SYSTEMS, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

Fair Value - The Financial Accounting Standards Board (FASB) Codification defines fair value, and establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurements) and the lowest priority to unobservable inputs (level 3 measurements). The three levels of the fair value hierarchy under the FASB Codification include:

Level 1 - Inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date.

Level 2 - Valuations based on quoted prices in markets that are not active or for which all significant inputs are observable, either directly or indirectly.

Level 3 - Prices or valuations that require inputs that are both significant to the fair value measurement and unobservable.

To the extent that valuation is based on models or inputs that are less observable or unobservable in the market, the determination of fair value requires more judgment. Accordingly, the degree of judgment exercised by the Company in determining fair value is greatest for instruments categorized in Level 3. A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement.

Fair value is a market-based measure considered from the perspective of a market participant rather than an entity-specific measure. Therefore, even when market assumptions are not readily available, the Company's own assumptions are set to reflect those that market participants would use in pricing the asset or liability at the measurement date. The Company uses prices and inputs that are current as of the measurement date, including during periods of market dislocation. In periods of market dislocation, the observability of prices and inputs may be reduced for many instruments. This condition could cause an instrument to be reclassified from Level 1 to Level 2 or from Level 2 to Level 3.

There have been no changes in the valuation techniques used during the current period.

Utility Revenue Recognition - Electric Operating Revenues consist of billed and unbilled revenue and revenue from rate adjustment mechanisms. Billed and unbilled revenue includes delivery revenue and pass-through revenue, recognized according to tariffs approved by the NHPUC which determines the amount of revenue the Company will record for these items. Revenue from rate adjustment mechanisms is recognized as accrued revenue and authorized by the NHPUC for recognition in the current period for future cash recoveries from, or credits to, customers.

Billed and unbilled revenue is recorded when service is rendered or energy is delivered to customers. However, the determination of energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenues are calculated. These unbilled revenues are estimated each month based on estimated customer usage by class and applicable customer rates, taking into account current and historical weather data, assumptions pertaining to metering patterns, billing cycle statistics, and other estimates and assumptions and are then reversed in the following month when billed to customers.

A majority of the Company's revenue from contracts with customers continues to be recognized on a monthly basis based on applicable tariffs and customer monthly consumption. Such revenue is recognized

UNITIL ENERGY SYSTEMS, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

using the invoice practical expedient which allows an entity to recognize revenue in the amount that directly corresponds to the value transferred to the customer.

The Company's billed and unbilled revenue meets the definition of "revenues from contracts with customers" as defined in Accounting Standards Codification (ASC) 606. Revenue recognized in connection with rate adjustment mechanisms is consistent with the definition of alternative revenue programs in ASC 980-605-25-3, as the Company has the ability to adjust rates in the future as a result of past activities or completed events. The rate adjustment mechanisms meet the criteria within ASC 980-605-25-4. In cases where allowable costs are greater than operating revenues billed in the current period for the individual rate adjustment mechanism, additional operating revenue is recognized. In cases where allowable costs are less than operating revenues billed in the current period for the individual rate adjustment mechanism, operating revenue is reduced. ASC 606 requires the Company to disclose separately the amount of revenues from contracts with customers and from alternative revenue programs.

The following table presents revenue classified by the types of goods/services rendered and market/customer type.

	Twelve Months Ended December 31,		
Electric Operating Revenues ($ millions):	**2020**	**2019**	**2018**
Billed and Unbilled Revenue:			
Residential	$ 89.7	$ 85.6	$ 86.7
C&I	66.3	67.4	69.9
Other	2.8	3.6	4.4
Total Billed and Unbilled Revenue	158.8	156.6	161.0
Rate Adjustment Mechanism Revenue	0.1	5.2	(3.4)
Total Electric Operating Revenues	**$ 158.9**	**$ 161.8**	**$ 157.6**

Retirement Benefit Obligations - The Company co-sponsors the Unitil Corporation Retirement Plan (Pension Plan). The Pension Plan is closed to new non-union employees. The Pension Plan was closed to union employees covered under the collective bargaining agreement, entered into during 2012 between Unitil Energy and IBEW Local 1837, and hired subsequent to June 1, 2012. The Company also co-sponsors a non-qualified retirement plan, the Unitil Corporation Supplemental Executive Retirement Plan (SERP), covering certain executives of the Company and an employee 401(k) savings plan. Additionally, the Company co-sponsors the Unitil Employee Health and Welfare Benefits Plan (PBOP Plan), primarily to provide health care and life insurance benefits to retired employees.

The Company records on its balance sheets a liability for the underfunded status of its retirement benefit obligations (RBO) based on the projected benefit obligation. The Company has recognized a corresponding Regulatory Asset, to recognize the future collection of these obligations in electric rates. See Note 8 (Retirement Benefit Obligations).

Depreciation - Depreciation expense is calculated on a group straight-line basis based on the useful lives of assets, and judgment is involved when estimating the useful lives of certain assets. The Company conducts independent depreciation studies on a periodic basis as part of the regulatory ratemaking process and considers the results presented in these studies in determining the useful lives of the Company's fixed assets. A change in the estimated useful lives of these assets could have a material impact on the Company's Financial Statements. Provisions for depreciation were equivalent to the following composite rates, based on the average depreciable property balances at the beginning and end of each year: 2020 - 3.48%, 2019 - 3.47% and 2018 - 3.48%. Depreciation expense for Unitil Energy was $12.7 million, $11.9 million and $11.4 million for the years ended December 31, 2020, 2019 and 2018, respectively.

Income Taxes - The Company is subject to Federal and State income taxes as well as various other business taxes. This process involves estimating the Company's current tax liabilities as well as assessing temporary and permanent differences resulting from the timing of the deductions of expenses and recognition of taxable income for tax and book accounting purposes. These temporary differences result in deferred tax assets and liabilities, which are included in the Company's Balance Sheets. The Company accounts for income tax assets, liabilities and expenses in accordance with the FASB Codification guidance on Income Taxes. The Company classifies penalty and interest expense related to income tax liabilities as income tax expense and interest expense, respectively, in the Statements of Earnings.

Provisions for income taxes are calculated in each of the jurisdictions in which the Company operates for each period for which a statement of earnings is presented. The Company accounts for income taxes in accordance with the FASB Codification guidance on Income Taxes, which requires an asset and liability approach for the financial accounting and reporting of income taxes. Significant judgments and estimates are required in determining current and deferred tax assets and liabilities. The Company's deferred tax assets and liabilities reflect its best assessment of estimated future taxes to be paid. In accordance with the FASB Codification, the Company periodically assesses the realization of its deferred tax assets and liabilities and adjusts the income tax provision, the current tax liability and deferred taxes in the period in which the facts and circumstances which gave rise to the revision become known.

Unitil Corporation and its subsidiaries, including Unitil Energy, file consolidated federal income tax returns as well as combined or separate state income tax returns. Federal and state income taxes paid by Unitil Corporation are collected from, or refunded to, Unitil Corporation's subsidiaries based on a tax sharing agreement between Unitil Corporation and each of its affiliated subsidiaries. The tax sharing agreement apportions taxes paid among Unitil Corporation and its subsidiaries as though each affiliate had filed a separate tax return.

Cash and Cash Equivalents - Cash and Cash Equivalents includes all cash and cash equivalents to which the Company has legal title. Cash equivalents include short-term investments with original maturities of three months or less and interest bearing deposits. Under the Independent System Operator – New England (ISO-NE) Financial Assurance Policy (Policy), the Company is required to provide assurance of its ability to satisfy its obligations to ISO-NE. Under this Policy, the Company provides cash deposits covering approximately 2-1/2 months of outstanding obligations. On December 31, 2020 and 2019, the Company had deposited $2.2 million and $1.5 million, respectively, to satisfy its ISO-NE Policy obligations. These amounts are included in Cash and Cash Equivalents on the Company's Balance Sheets.

Allowance for Uncollectible Accounts - The Company recognizes a provision for doubtful accounts that reflects the Company's estimate of expected credit losses for electric utility service accounts receivable. The allowance for doubtful accounts is calculated by applying a historical loss rate, which is adjusted for current conditions, customer trends, or other factors such as macroeconomic conditions, to customer account balances. The Company also calculates the amount of written-off receivables that are recoverable through regulatory rate reconciling mechanisms. The Company is authorized by the NHPUC to recover the costs of its energy commodity portion of bad debts through rate mechanisms. Evaluating the adequacy of the allowance for doubtful accounts requires judgment about the assumptions used in the analysis. The Company's experience has been that the assumptions used in evaluating the adequacy of the allowance for doubtful accounts have proven to be reasonably accurate.

UNITIL ENERGY SYSTEMS, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

Accounts Receivable, Net includes $0.5 million and $0.2 million of the Allowance for Doubtful Accounts at December 31, 2020 and December 31, 2019, respectively. Unbilled Revenues, net (a component of Accrued Revenue) includes $0.1 million of the Allowance for Doubtful Accounts at December 31, 2020.

Accrued Revenue - Accrued Revenue includes the current portion of Regulatory Assets (see "Regulatory Accounting") and unbilled revenues (see "Utility Revenue Recognition") The following table shows the components of Accrued Revenue as of December 31, 2020 and 2019.

	December 31,	
Accrued Revenue ($ millions)	**2020**	2019
Regulatory Assets – Current	**$ 7.2**	$ 8.4
Unbilled Revenues	**5.0**	4.9
Total Accrued Revenue	**$ 12.2**	$ 13.3

Materials and Supplies - Materials and Supplies consist of distribution line construction and repair materials. It also consists of distribution substation repair materials. Materials and Supplies are stated at average cost and are issued from stock using the average cost of existing stock. Materials and Supplies are recorded when purchased and subsequently charged to expense or capitalized to property, plant, and equipment when installed. Materials and Supplies were $1.4 million and $1.4 million at December 31, 2020 and 2019, respectively.

Utility Plant - The cost of additions to Utility Plant and the cost of renewals and betterments are capitalized. Cost consists of labor, materials, services and certain indirect construction costs, including an allowance for funds used during construction (AFUDC). The average interest rates applied to AFUDC were 3.84%, 3.48% and 2.88% in 2020, 2019 and 2018, respectively. The costs of current repairs and minor replacements are charged to operating expense accounts. The original cost of utility plant retired or otherwise disposed of and the cost of removal, less salvage, are charged to the accumulated provision for depreciation. The Company includes in its mass asset depreciation rates, which are periodically reviewed as part of its ratemaking proceedings, cost of removal amounts to provide for future negative salvage value. At December 31, 2020 and 2019, the cost of removal amounts, which are recorded on the Company's Balance Sheets in Cost of Removal Obligations, were estimated to be $22.9 million and $21.5 million, respectively.

Regulatory Accounting - Unitil Energy's principal business is the distribution of electricity. The Company is subject to regulation by the NHPUC and the FERC. Accordingly, the Company uses the Regulated Operations guidance as set forth in the FASB Codification. The Company has recorded Regulatory Assets and Regulatory Liabilities which will be recovered from customers, or applied for customer benefit, in accordance with rate provisions approved by the applicable public utility regulatory commission.

UNITIL ENERGY SYSTEMS, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

	December 31,	
Regulatory Assets consist of the following ($ millions)	**2020**	2019
Retirement Benefits	**$ 39.2**	$ 34.2
Energy Supply & Other Rate Adjustment Mechanisms	**5.7**	6.8
Deferred Storm Charges	**4.1**	5.6
Other	**2.2**	1.8
Total Regulatory Assets	**$ 51.2**	$ 48.4
Less: Current Portion of Regulatory Assets [(1)]	**7.2**	8.4
Regulatory Assets – noncurrent	**$ 44.0**	$ 40.0

(1) Reflects amounts included in Accrued Revenue on the Company's Balance Sheets.

	December 31,	
Regulatory Liabilities consist of the following ($ millions)	**2020**	**2019**
Rate Adjustment Mechanisms	**$ 1.9**	$ 2.0
Income Taxes	**16.6**	16.6
Total Regulatory Liabilities	**18.5**	18.6
Less: Current Portion of Regulatory Liabilities	**1.9**	2.0
Regulatory Liabilities - noncurrent	**$ 16.6**	$ 16.6

Generally, the Company receives a return on investment on its Regulatory Assets for which a cash outflow has been made. Regulatory commissions can reach different conclusions about the recovery of costs, which can have a material impact on the Company's Financial Statements. The Company believes it is probable that it will recover its investments in long-lived assets, including regulatory assets.

If the Company, or a portion of its assets or operations, were to cease meeting the criteria for application of these accounting rules, accounting standards for businesses in general would become applicable and immediate recognition of any previously deferred costs, or a portion of deferred costs, would be required in the year in which the criteria are no longer met, if such deferred costs were not recoverable in the portion of the business that continues to meet the criteria for application of the FASB Codification topic on Regulated Operations. If unable to continue to apply the FASB Codification provisions for Regulated Operations, the Company would be required to apply the provisions for the Discontinuation of Rate-Regulated Accounting included in the FASB Codification. In the Company's opinion, its regulated operations will be subject to the FASB Codification provisions for Regulated Operations for the foreseeable future.

Leases - The Company records assets and liabilities on the balance sheet for all leases with terms longer than 12 months. Leases are classified as either finance or operating, with classification affecting the pattern of expense recognition in the income statement. The Company has elected the practical expedient to not separate non-lease components from lease components and instead to account for both as a single lease component. The Company's accounting policy election for leases with a lease term of 12 months or less is to recognize the lease payments as lease expense on a straight-line basis over the lease term. The Company recognizes those lease payments in the Statements of Earnings on a straight-line basis over the lease term. See additional discussion in the "Leases" section of Note 2 (Debt and Financing Arrangements).

UNITIL ENERGY SYSTEMS, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

Derivatives - The Company enters into wholesale electric energy supply contracts to serve its customers. The Company's policy is to review each contract and determine whether the contract meets the criteria for classification as a derivative. As of December 31, 2020, the Company determined that none of its wholesale electric energy supply contracts met the criteria for recognition as a derivative instrument as the contracts qualify for the normal purchase and sale scope exemption in accordance with the FASB Codification guidance for derivative instruments.

Energy Supply Obligations - The following discussion and table summarize the nature and amounts of the items recorded as Energy Supply Obligations on the Company's Balance Sheets.

Power Supply Contract Divestitures - As a result of the restructuring of the utility industry in New Hampshire, Unitil Energy's customers have the opportunity to purchase their electric supply from third-party suppliers. In connection with the implementation of retail choice, Unitil Power, which formerly functioned as the wholesale power supply provider for Unitil Energy, divested its long-term power supply contracts through the sale of the entitlements to the electricity sold under those contracts. Unitil Energy recovers in its rates all the costs associated with the divestiture of its power supply portfolios and has secured regulatory approval from the NHPUC for the recovery of power supply-related stranded costs. As of December 31, 2020, the obligations related to these divestitures were $0.3 million and are recorded in Energy Supply Obligations on the Company's Balance Sheets with corresponding regulatory assets recorded in Accrued Revenue.

Renewable Energy Portfolio Standards - Renewable Energy Portfolio Standards (RPS) require retail electricity suppliers, including public utilities, to demonstrate that required percentages of their sales are met with power generated from certain types of resources or technologies. Compliance is demonstrated by purchasing and retiring Renewable Energy Certificates (REC) generated by facilities approved by the state as qualifying for REC treatment. Unitil Energy purchases RECs in compliance with RPS legislation in New Hampshire for supply provided to default service customers. RPS compliance costs are a supply cost that is recovered in customer default service rates. Unitil Energy collects RPS compliance costs from customers throughout the year and demonstrates compliance for each calendar year on the following July 1. Due to timing differences between collection of revenue from customers and payment of REC costs to suppliers, Unitil Energy typically maintains accrued revenue for RPS compliance which is recorded in Accrued Revenue with a corresponding liability in Energy Supply Obligations on the Company's Balance Sheets.

Energy Supply Obligations consist of the following: ($ millions)	**December 31, 2020**	2019
Current:		
Power Supply Contract Divestitures	**$ 0.3**	$ 0.3
Renewable Energy Portfolio Standards	**3.3**	2.8
Total Energy Supply Obligations – Current	**$ 3.6**	$ 3.1
Long-Term:		
Power Supply Contract Divestitures	**$ ---**	$ 0.3
Total Energy Supply Obligations	**$ 3.6**	$ 3.4

Off-Balance Sheet Arrangements - As of December 31, 2020, the Company does not have any significant arrangements that would be classified as Off-Balance Sheet Arrangements.

Concentrations of Credit Risk - Financial instruments that subject the Company to credit risk concentrations consist of cash and cash equivalents and accounts receivable. The Company's cash and cash equivalents are held at financial institutions and at times may exceed federally insured limits. The Company has not experienced any losses in such accounts. Accounts receivable may be affected by changes in economic conditions. However, the Company believes that the credit risk associated with accounts receivable is offset by the diversification of the Company's customer base. The Company believes it is not exposed to any significant credit risk on cash and cash equivalents and accounts receivable.

Commitments and Contingencies - The Company's accounting policy is to record and/or disclose commitments and contingencies in accordance with the FASB Codification as it applies to an existing condition, situation, or set of circumstances involving uncertainty as to possible loss that will ultimately be resolved when one or more future events occur or fail to occur. As of December 31, 2020, the Company is not aware of any material commitments or contingencies other than those disclosed in the Commitments and Contingencies footnote to the Company's Financial Statements below. See Note 6 (Commitments and Contingencies).

Subsequent Events - The Company has evaluated all events or transactions through March 22, 2021, the date the Financial Statements were available to be issued. During this period, the Company did not have any material subsequent events that would result in adjustment to or disclosure in its Financial Statements.

NOTE 2: DEBT AND FINANCING ARRANGEMENTS

Long-Term Debt and Interest Expense

Substantially all property of the Company is subject to liens of indenture under which First Mortgage Bonds (FMB) have been issued. Certain of the Company's long-term debt agreements contain provisions, which, among other things, limit the incursion of additional long-term debt. In order to issue new FMB securities, customary covenants of the existing Unitil Energy Indenture Agreement must be met, including that Unitil Energy has sufficient available net bondable plant to issue the securities and projected earnings available for interest charges are equal to at least two times the annual interest requirement. The Unitil Energy agreements further require that if Unitil Energy defaults on any Unitil Energy FMB securities, it would constitute a default for all Unitil Energy FMB securities. The Unitil Energy default provisions are not triggered by the actions or defaults of other companies owned by Unitil Corporation. The Unitil Energy Indenture Agreement contains covenants restricting the ability of the Company to incur additional liens and to enter into sale and leaseback transactions, and restricting the ability of the Company to consolidate with, to merge with or into or to sell or otherwise dispose of all or substantially all of its assets.

On September 15, 2020, Unitil Energy issued $27.5 million of First Mortgage Bonds due September 15, 2040 at 3.58%. Unitil Energy used the net proceeds from this offering to repay short term debt and for general corporate purposes. Approximately $0.2 million of costs associated with this issuance have been recorded as a reduction to Long-Term Debt for presentation purposes on the Balance Sheets.

UNITIL ENERGY SYSTEMS, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

Details of long-term debt at December 31, 2020 and 2019 are shown in the following table:

Long-term Debt ($ millions)	December 31, 2020	2019
First Mortgage Bonds:		
5.24% Senior Secured Notes, Due March 2, 2020 (1)	$ ---	$ 5.0
8.49% Senior Secured Notes, Due October 14, 2024	3.0	4.5
6.96% Senior Secured Notes, Due September 1, 2028	16.0	18.0
8.00% Senior Secured Notes, Due May 1, 2031	15.0	15.0
6.32% Senior Secured Notes, Due September 15, 2036	15.0	15.0
3.58% Senior Secured Notes, Due September 15, 2040	27.5	---
4.18% Senior Secured Notes, Due November 30, 2048	30.0	30.0
Total Long-Term Debt	106.5	87.5
Less: Unamortized Debt Issuance Costs	1.3	1.2
Total Long-Term Debt, net of Unamortized Debt Issuance Costs	105.2	86.3
Less: Current Portion	3.4	8.4
Total Long-Term Debt, Less Current Portion	$ 101.8	$ 77.9

(1) The 5.24% Senior Secured Notes were fully paid off in the first quarter of 2020.

The aggregate amount of bond repayment requirements is $3.5 million in 2021; $5.0 million in 2022; $3.5 million in each of 2023, 2024 and 2025; and $87.5 million thereafter.

The fair value of the Company's long-term debt is estimated based on quoted market prices for the same or similar issues, or on current rates offered to the Company for debt of the same remaining maturities. The fair value of the Company's long-term debt at December 31, 2020 is estimated to be approximately $127.1 million, before considering any costs, including prepayment costs, to market the Company's debt. Currently, management believes that there is no active market in the Company's debt securities, which have all been sold through private placements. If there were an active market for the Company's debt securities, the fair value of the Company's long-term debt would be estimated based on quoted market prices for the same or similar issues, or on current rates offered to the Company for debt of the same remaining maturities. The fair value of the Company's long-term debt is estimated using Level 2 inputs (valuations based on quoted prices available in active markets for similar assets or liabilities, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are directly observable, and inputs derived principally from market data.) In estimating the fair value of the Company's long-term debt, the assumed market yield reflects the Moody's Baa Utility Bond Average Yield. Costs, including prepayment costs, associated with the early settlement of long-term debt are not taken into consideration in determining fair value.

Credit Arrangements

Unitil Energy's short-term borrowings are presently provided under a cash pooling and loan agreement between Unitil Corporation and its subsidiaries. Under the existing pooling and loan agreement, Unitil Corporation borrows, as required, from its banks on behalf of its subsidiaries. At December 31, 2020, Unitil

UNITIL ENERGY SYSTEMS, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

Corporation had unsecured committed bank lines of credit for short-term debt aggregating $120 million. The weighted average interest rates on all short-term borrowings were 1.7%, 3.4% and 3.3% during 2020, 2019 and 2018, respectively. Unitil Energy had short-term debt outstanding through bank borrowings of approximately $8.2 million and $13.1 million at December 31, 2020 and December 31, 2019, respectively.

Leases

The Company leases some of its vehicles, machinery and office equipment under operating lease arrangements.

Total rental expense under operating leases charged to operations for the years ended December 31, 2020, 2019 and 2018 amounted to $0.5 million, $0.4 million and $0.5 million respectively.

The balance sheet classification of the Company's lease obligations is presented in the following table:

Lease Obligations (millions)	December 31, 2020	December 31, 2019
Operating Lease Obligations:		
Other Current Liabilities (current portion)	**$ 0.5**	$ 0.3
Operating Leases, Less Current Portion (noncurrent portion)	**1.2**	1.1
Total Lease Obligations	**$ 1.7**	$ 1.4

Cash paid for amounts included in the measurement of operating lease obligations for the twelve months ended December 31, 2020 and 2019 were $0.5 million and $0.4 million, respectively, and were included in Cash Provided by Operating Activities on the Statements of Cash Flows.

The following table is a schedule of future operating lease payment obligations as of December 31, 2020. The payments for operating leases consist of $0.5 million of current operating lease obligations, which are included in Other Current Liabilities and $1.2 million of noncurrent operating lease obligations, which are included in Operating Leases, Less Current Portion, on the Company's Balance Sheets as of December 31, 2020.

Lease Payments (000's) Year Ending December 31,	Operating Leases
2021	$ 548
2022	475
2023	386
2024	248
2025	93
2026-2030	70
Total Payments	**1,820**
Less: Interest	137
Amount of Lease Obligations Recorded on Balance Sheets	**$ 1,683**

UNITIL ENERGY SYSTEMS, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

Operating lease obligations are based on the net present value of the remaining lease payments over the remaining lease term. In determining the present value of lease payments, the Company used the interest rate stated in each lease agreement. As of December 31, 2020, the weighted average remaining lease term is 3.9 years and the weighted average operating discount rate used to determine the operating lease obligations was 4.1%. As of December 31, 2019, the weighted average remaining lease term is 4.1 years and the weighted average operating discount rate used to determine the operating lease obligations was 4.6%.

NOTE 3: RESTRICTION ON DIVIDENDS

Under the terms of the Indenture of Mortgage and Deed of Trust and the supplemental indentures thereto relating to Unitil Energy's First Mortgage Bonds, $79.0 million was available for dividends and similar distributions at December 31, 2020. Common dividends declared by Unitil Energy are paid exclusively to Unitil Corporation.

NOTE 4: NON-REDEEMABLE, NON-CUMULATIVE PREFERRED STOCK

The 6% Non-Redeemable, Non-Cumulative Preferred Stock ranks senior to Common Stock and the holders thereof are entitled in liquidation to receive $100 per share, plus accrued dividends. At December 31, 2020, the liquidation value of the Company's Preferred Stock was $0.2 million.

NOTE 5: ENERGY SUPPLY

Electric Supply:

Unitil Energy is a member of the New England Power Pool (NEPOOL) and participates in the Independent System Operator-New England (ISO-NE) markets for the purpose of facilitating wholesale electric power supply transactions, which are necessary to serve its electric customers with their supply of electricity.

Unitil Energy's customers are entitled to purchase their electric supply from competitive third-party suppliers. As of December 2020, nearly 77% of Unitil Energy's largest customers, representing 23% of the Company's electric kilowatt-hour (kWh) sales, are purchasing their electric power supply in the competitive market.

The percentage of residential customers purchasing electricity from a third party supplier is 8.3%, down 0.6% from 2019 and reflecting a downward trend from a high of 13% in 2015. Most residential and small commercial customers continue to purchase their electric supply through Unitil Energy under regulated energy rates and tariffs.

Regulated Electric Power Supply

In order to provide regulated electric supply service to its customers, Unitil Energy enters into load-following wholesale electric power supply contracts to purchase electric supply from various wholesale suppliers.

Unitil Energy currently has power supply contracts with various wholesale suppliers for the provision of Default Service to its customers. Currently, with approval of the NHPUC, Unitil Energy purchases Default Service power supply contracts for small, medium and large customers every six months for 100% of the supply requirements.

The NHPUC regularly reviews alternatives to its procurement policy, which may lead to future changes in this regulated power supply procurement structure.

UNITIL ENERGY SYSTEMS, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

Regional Electric Transmission and Power Markets

Unitil Energy, as well as virtually all New England electric utilities, participates in the ISO-NE markets. ISO-NE is the Regional Transmission Organization (RTO) in New England. The purpose of ISO-NE is to assure reliable operation of the bulk power system in the most economical manner for the region. Substantially all operation and dispatching of electric generation and bulk transmission capacity in New England are performed on a regional basis. The ISO-NE tariff imposes generating capacity and reserve obligations, and provides for the use of major transmission facilities and support payments associated therewith. The most notable benefits of the ISO-NE are coordinated, reliable power system operation and a supportive business environment for the development of competitive electric markets.

Electric Power Supply Divestiture

In connection with the implementation of retail choice, Unitil Power, which formerly functioned as the wholesale power supply provider for Unitil Energy, divested its long-term power supply contracts through the sale of the entitlements to the electricity sold under those contracts. Unitil Energy recovers in its rates all the costs associated with the divestiture of its power supply portfolios and has secured regulatory approval from the NHPUC for the recovery of power supply-related stranded costs and other restructuring-related regulatory assets. The Company has a continuing obligation to submit regulatory filings that demonstrate its compliance with regulatory mandates and provide for timely recovery of costs in accordance with its approved restructuring plan.

NOTE 6: COMMITMENTS AND CONTINGENCIES

Regulatory Matters - Overview - Unitil Energy distributes electricity to approximately 77,200 customers in New Hampshire in the capital city of Concord as well as parts of 12 surrounding towns and all or part of 18 towns in the southeastern and seacoast regions of New Hampshire, at rates established under traditional cost of service regulation. Under this regulatory structure, Unitil Energy recovers the cost of providing distribution service to its customers based on a representative test year, in addition to earning a return on its capital investment in utility assets. The Company's customers have the opportunity to purchase their electric supplies from third-party suppliers. Most small and medium-sized customers, however, continue to purchase such supplies through Unitil Energy as the provider of default service energy supply. Unitil Energy purchases electricity for default service from unaffiliated wholesale suppliers and recovers the actual costs of these supplies, without profit or markup, through reconciling, pass-through rate mechanisms that are periodically adjusted.

Unitil Energy provides electric distribution service to its customers pursuant to rates approved by the NHPUC. See "Base Rates" for a discussion of the Company's current rates. As the provider of last resort, Unitil Energy also provides its customers with electric power through Default Service at rates which reflect Unitil Energy's costs for wholesale supply with no profit or markup. Unitil Energy procures Default Service power for its larger commercial and industrial customers on a quarterly basis, and for its smaller commercial and residential customers through a portfolio of longer term contracts procured on a semi-annual basis. Unitil Energy recovers its costs for this service on a pass-through basis through reconciling rate mechanisms.

Tax Cuts and Jobs Act of 2017 - On December 22, 2017, the Tax Cuts and Jobs Act of 2017 (TCJA) was signed into law. Among other things, the TCJA substantially reduced the corporate income tax rate to 21%, effective January 1, 2018. The NHPUC issued an order directing how the tax law changes were to be reflected in rates. Unitil Energy has complied with this order and has made the required changes to its rates as directed by the NHPUC.

UNITIL ENERGY SYSTEMS, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

On November 21, 2019, FERC issued Order No. 864, a final rule on Public Utility Transmission Rate Changes to Address Accumulated Deferred Income Taxes. The new rule requires public utilities with formula transmission rates to revise their formula rates to include a transparent methodology to address the TCJA and future tax law changes on customer rates by accounting for "excess" or "deficient" Accumulated Deferred Income Taxes (ADIT). FERC also required transmission providers with stated rates to account for TCJA's effect on ADIT in their next rate case. The Company is complying with the new rule and there is no material effect on its financial position, operating results, or cash flows.

Base Rates - On April 20, 2017 the NHPUC issued its final order effective May 1, 2017, providing for a permanent increase of $4.1 million followed by two annual rate step adjustments to recover the revenue requirements associated with certain capital expenditures. On April 30, 2018, the NHPUC approved Unitil Energy's first step increase, effective May 1, 2018. On April 22, 2019, the NHPUC approved Unitil Energy's second and final step adjustment, providing a revenue increase of approximately $340,000, effective May 1, 2019.

Financial Effects of COVID-19 Pandemic - The NHPUC has opened a proceeding to consider the revenue and cost effects on the regulated gas and electric utilities within their respective jurisdictions of the requirement to continue the availability of gas, electric and water service to customers during the COVID-19 pandemic. Among the effects under investigation are the revenue effects associated with service disconnection moratoriums, the waiver of certain fees and expanded customer payments arrangements; the increased cost of customer accounts that cannot be collected, including the cost of bad debt reserves and increased working capital costs; and increased operating and maintenance costs incurred for employees to work safely and protect the public. Unitil Energy is an active participant in these proceedings, and is in full compliance with all regulatory orders governing service shut-off moratoriums and other customer service protection measures. These matters remain pending.

Reconciliation Filings - Unitil Energy has a number of regulatory reconciling accounts which require annual or semi-annual filings with the NHPUC to reconcile costs and revenues and seek approval of any rate changes. These filings include: annual electric reconciliation filings for a number of items, including default service, stranded cost charges and transmission charges; costs associated with energy efficiency programs in New Hampshire as directed by the NHPUC; recovery of the ongoing costs of storm repairs incurred by Unitil Energy; and the actual wholesale energy costs for electric power incurred by Unitil Energy. Unitil Energy has been, and remains in full compliance with all directives and orders regarding these filings. The Company considers these to be routine regulatory proceedings and there are no material issues outstanding.

Litigation - The Company is involved in legal and administrative proceedings and claims of various types, which arise in the ordinary course of business. The Company believes, based upon information furnished by counsel and others, that the ultimate resolution of these claims will not have a material impact on its financial position, operating results or cash flows.

Market Risk - Although the Company is subject to commodity price risk as part of its traditional operations, the current regulatory framework within which the Company operates allows for full collection of approved fuel costs in rates. Consequently, there is limited commodity price risk after consideration of the related rate-making. Additionally, the Company has divested its commodity-related contracts and therefore, has further reduced its exposure to commodity risk.

UNITIL ENERGY SYSTEMS, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

NOTE 7: INCOME TAXES

Provisions for Federal and State Income Taxes reflected as operating expenses in the accompanying consolidated statements of earnings for the years ended December 31, 2020, 2019 and 2018 are shown in the following table:

	(000's) 2020	2019	2018
Current Income Tax Provision			
Federal	$ —	$ —	$ —
State	—	—	—
Total Current Income Taxes	—	—	—
Deferred Income Tax Provision			
Federal	**2,169**	2,040	2,477
State	**861**	811	730
Total Deferred Income Taxes	**3,030**	2,851	3 207
Total Income Tax Expense	**$ 3,030**	$ 2,851	$ 3,207

The differences between the Company's provisions for Income Taxes and the provisions calculated at the statutory federal tax rate, expressed in percentages, are shown in the following table:

	2020	2019	2018
Statutory Federal Income Tax Rate	**21%**	**21%**	21%
Income Tax Effects of:			
State Income Taxes, net	**6**	**6**	6
Utility Plant Differences	—	—	—
Effective Income Tax Rate	**27%**	**27%**	27%

UNITIL ENERGY SYSTEMS, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

Temporary differences which gave rise to deferred tax assets and liabilities in 2020 and 2019, are shown in the following table:

Temporary Differences (000's)		**2020**		2019
Deferred Tax Assets				
Retirement Benefit Obligations	$	**16,164**	$	14,592
Net Operating Loss Carryforwards		**---**		2,520
Other, net		**150**		142
Total Deferred Tax Assets	$	**16,314**	$	17,254
Deferred Tax Liabilities				
Utility Plant Differences	$	**40,134**	$	38,429
Regulatory Assets & Liabilities		**2,104**		827
Other, net		**337**		468
Total Deferred Tax Liabilities		**42,575**		39,724
Net Deferred Tax Liabilities	$	**26,261**	$	22,470

In March 2020, the Coronavirus Aid, Relief and Economic Security (CARES) Act was signed into law. The CARES Act included several tax changes as part of its economic package. These changes principally related to expanded Net Operating Loss (NOL) carryback periods, increases to interest deductibility limitations, and accelerated Alternative Minimum Tax (AMT) refunds. The Company has evaluated these items and determined that these items do not have a material impact on the Company's financial statements as of December 31, 2020. Additionally, the CARES Act enacted the Employment Retention Credit (ERC) to incentivize companies to retain employees. The ERC is a 50% credit on employee wages for employees that are retained and cannot perform their job duties at 100% capacity as a result of coronavirus pandemic restrictions. The ERC is taken as a credit on employment tax form 941. In the third quarter of 2020, the Company recorded an ERC of $32.5 thousand as a reduction to employment tax expense which is recorded as a reduction to Taxes other than Income Taxes in the consolidated statement of earnings.

In December 2020, the Consolidated Appropriations Act, 2021 (CAA) was signed into law. The CAA included additional funding through tax credits as part of its economic package for 2021. The Company evaluated these items in its tax computation as of December 31, 2020 and determined that these items do not have a material impact on the Company's financial statements as of December 31, 2020.

In December 2017, the TCJA, which included a reduction to the corporate federal income tax rate to 21% effective January 1, 2018, was signed into law. In accordance with GAAP Accounting Standard 740, the Company revalued its Accumulated Deferred Income Taxes (ADIT) at the new 21% tax rate at which the ADIT will be reversed in future periods. As of December 31, 2020 and December 31, 2019 the Company had recorded a net Regulatory Liability in the amount of $16.6 million and $16.6 million, respectively, as a result of the ADIT revaluation.

Based on communications received by the Company from its state regulators in rate cases and other regulatory proceedings in the first quarter of 2018 and as prescribed in the TCJA, the recent FERC guidance and IRS normalization rules; the benefit of these excess ADIT amounts will be subject to flow back to customers in future utility rates according to the Average Rate Assumption Method (ARAM). ARAM reconciles excess ADIT at the reversal rate of the underlying book/tax temporary timing differences. The Company estimates the ARAM flow back period to be approximately twenty years, for protected and unprotected excess ADIT. New Hampshire liabilities will begin to flow back once rate proceedings have finalized in that jurisdiction.

UNITIL ENERGY SYSTEMS, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

The Company evaluated its tax positions at December 31, 2020 in accordance with the FASB Codification, and has concluded that no adjustment for recognition, derecognition, settlement and foreseeable future events to any tax liabilities or assets as defined by the FASB Codification is required. The Company remains subject to examination by Federal and New Hampshire tax authorities for the tax periods ended December 31, 2017; December 31, 2018; and December 31, 2019. Income tax filings for the year ended December 31, 2019 have been filed with the New Hampshire Department of Revenue Administration.

NOTE 8: RETIREMENT BENEFIT OBLIGATIONS

The Company co-sponsors the following retirement benefit plans to provide certain pension and postretirement benefits for its retirees and current employees as follows:

- The Unitil Corporation Retirement Plan (Pension Plan) - The Pension Plan is a defined benefit pension plan. Under the Pension Plan, retirement benefits are based upon an employee's level of compensation and length of service. The Pension Plan is closed to new non-union employees. The Pension Plan was closed to union employees covered under the collective bargaining agreement, entered into during 2012 between Unitil Energy and IBEW Local 1837, and hired subsequent to June 1, 2012.
- The Unitil Retiree Health and Welfare Benefits Plan (PBOP Plan) - The PBOP Plan provides health care and life insurance benefits to retirees. The Company has established Voluntary Employee Benefit Trusts (VEBT), into which it funds contributions to the PBOP Plan.
- The Unitil Corporation Supplemental Executive Retirement Plan (SERP) - The SERP is a non-qualified retirement plan, with participation limited to executives selected by the Board of Directors.

The following table includes the key assumptions used in determining the Company's benefit plan costs and obligations:

Used to Determine Plan costs for years ended December 31:	**2020**	2019	2018
Discount Rate	**3.25%**	4.25%	3.60%
Rate of Compensation Increase	**3.00%**	3.00%	3.00%
Expected Long-term Rate of Return on Plan Assets	**7.40%**	7.50%	7.75%
Health Care Cost Trend Rate Assumed for Next Year	**7.00%**	7.00%	7.50%
Ultimate Health Care Cost Trend Rate	**4.50%**	4.50%	4.50%
Year that Ultimate Health Care Cost Trend Rate is reached	**2029**	2024	2024

UNITIL ENERGY SYSTEMS, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

Used to Determine Benefit Obligations at December 31:	**2020**	2019	2018
Discount Rate	**2.50%**	3.25%	4.25%
Rate of Compensation Increase	**3.00%**	3.00%	3.00%
Health Care Cost Trend Rate Assumed for Next Year	**6.60%**	7.00%	7.00%
Ultimate Health Care Cost Trend Rate	**4.50%**	4.50%	4.50%
Year that Ultimate Health care Cost Trend Rate is reached	**2029**	2029	2024

The Discount Rate assumptions used in determining retirement plan costs and retirement plan obligations are based on an assessment of current market conditions using high quality corporate bond interest rate indices and pension yield curves. The Rate of Compensation Increase assumption used in each of 2020, 2019 and 2018 was 3.00%, based on the expected long-term increase in compensation costs for personnel covered by the plans.

The following table provides the components of the Company's retirement plan costs (000's):

	Pension Plan			PBOP Plan			SERP		
	2020	2019	2018	**2020**	2019	2018	**2020**	2019	2018
Service Cost	**$ 892**	$ 830	$ 903	**$ 715**	$ 565	$ 724	**$ 80**	$ 70	$ 134
Interest Cost	**2,053**	2,319	2,070	**989**	1,060	1,035	**155**	160	111
Expected Return on Plan Assets	**(3,207)**	(3,030)	(2,741)	**(462)**	(356)	(345)	**---**	---	---
Prior Service Cost Amortization	**---**	---	2	**485**	484	484	**16**	16	52
Actuarial Loss Amortization	**2,374**	1,629	2,230	**325**	102	495	**291**	177	133
Sub-total	**2,112**	1,748	2,464	**2,052**	1,855	2,393	**542**	423	430
Amounts Capitalized and Deferred	**(1,052)**	(856)	(1,239)	**(1,161)**	(1,020)	(1,302)	**(159)**	(117)	(114)
NPBC Recognized	**$ 1,060**	$ 892	$ 1,225	**$ 891**	$ 835	$ 1,091	**$ 383**	$ 306	$ 316

UNITIL ENERGY SYSTEMS, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

The following table represents information on the plans' assets, projected benefit obligations (PBO), and funded status (000's):

	Pension Plan		PBOP Plan		SERP	
	2020	2019	**2020**	2019	**2020**	2019
Change in Plan Assets:						
Plan Assets at Beginning of Year	**$ 49,751**	$ 44,070	**$ 7,701**	$ 6,211	**$ ---**	$ ---
Actual Return on Plan Assets	**4,141**	6,171	**839**	931	**---**	---
Employer Contributions	**1,282**	1,889	**1,284**	1,169	**184**	172
Participant Contributions	**---**	---	**87**	41	**---**	---
Benefits Paid	**(2,078)**	(2,379)	**(951)**	(651)	**(184)**	(172)
Plan Assets at End of Year	**$ 53,096**	$ 49,751	**$ 8,960**	$ 7,701	**$ ---**	$ ---
Change in PBO:						
PBO at Beginning of Year	**$ 72,056**	$ 63,851	**$ 33,372**	$ 28,455	**$ 6,454**	$ 5,242
Service Cost	**892**	830	**715**	565	**80**	70
Interest Cost	**2,053**	2,319	**989**	1,060	**155**	160
Participant Contributions	**---**	---	**87**	41	**---**	---
Plan Amendments	**---**	---	**---**	---	**---**	64
Benefits Paid	**(2,078)**	(2,379)	**(951)**	(651)	**(184)**	(172)
Actuarial (Gain) or Loss	**6,714**	7,435	**2,157**	3,902	**567**	1,090
PBO at End of Year	**$ 79,637**	$ 72,056	**$ 36,369**	$ 33,372	**$ 7,072**	$ 6,454
Funded Status: Assets vs PBO	**$ (26,541)**	$ (22,305)	**$ (27,409)**	$ (25,671)	**$ (7,072)**	$ (6,454)

The increases in the PBO for the Pension and PBOP plans as of December 31, 2020 compared to December 31, 2019 reflects a decrease in the assumed discount rate as of December 31, 2020.

The funded status of the Pension, PBOP and SERP Plans is calculated based on the difference between the benefit obligation and the fair value of plan assets and is recorded on the balance sheets as an asset or a liability. Because the Company recovers the retiree benefit costs from customers through rates, regulatory assets are recorded in lieu of an adjustment to Accumulated Other Comprehensive Income/(Loss).

The Company has recorded on its Balance Sheets a liability for the underfunded status of its retirement benefit obligations based on the projected benefit obligation. The Company has recognized Regulatory Assets, net of tax, of $39.2 million and $34.2 million at December 31, 2020 and 2019, respectively, to recognize the future collection of these plan obligations in electric rates.

The Accumulated Benefit Obligation (ABO) is required to be disclosed for all plans where the ABO is in excess of plan assets. The difference between the PBO and the ABO is that the PBO includes projected compensation increases. The ABO for the Pension Plan was $73.5 million and $66.0 million as of December 31, 2020 and 2019, respectively. The ABO for the SERP was $5.9 million and $4.9 million as of December 31, 2020 and 2019, respectively. For the PBOP Plan, the ABO and PBO are the same.

The Company expects to continue to make contributions to its Pension Plan in 2021 and future years at minimum required and discretionary funding levels consistent with the amounts recovered in rates for these Pension Plan costs.

UNITIL ENERGY SYSTEMS, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

The following table represents employer contributions, participant contributions and benefit payments ($000's).

	Pension Plan			PBOP Plan			SERP		
	2020	2019	2018	**2020**	2019	2018	**2020**	2019	2018
Employer Contributions	**$ 1,282**	$ 1,889	$ 4,742	**$ 1,284**	$ 1,169	$ 1,130	**$ 184**	$ 172	$ 110
Participant Contributions	**$ ---**	$ ---	$ ---	**$ 87**	$ 41	$ 51	**$ ---**	$ ---	$ --
Benefit Payments	**$ 2,078**	$ 2,379	$ 1,800	**$ 951**	$ 651	$ 803	**$ 184**	$ 172	$ 110

The following table represents estimated future benefit payments ($000's).

	Estimated Future Benefit Payments		
	Pension	PBOP	SERP
2021	$ 2,449	$ 1,050	$ 179
2022	2,550	1,069	179
2023	2,713	1,163	179
2024	2,859	1,251	178
2025	3,077	1,335	333
2026 - 2030	$ 18,235	$ 7,418	$ 1,763

The Expected Long-Term Rate of Return on Pension Plan assets assumption used by the Company is developed based on input from actuaries and investment managers. The Company's Expected Long-Term Rate of Return on Pension Plan assets is based on target investment allocation of 56% in common stock equities, 39% in fixed income securities and 5% in real estate securities. The Company's Expected Long-Term Rate of Return on PBOP Plan assets is based on target investment allocation of 55% in common stock equities and 45% in fixed income securities. The actual investment allocations are shown in the following tables.

Pension Plan	**Target Allocation**	**Actual Allocation at December 31,**		
	2021	**2020**	**2019**	**2018**
Equity Funds	56%	**58%**	54%	49%
Debt Funds	39%	**37%**	36%	40%
Real Estate Fund	5%	**4%**	9%	10%
Other(1)	---	**1%**	1%	1%
Total		**100%**	100%	100%

(1) Represents investments being held in cash equivalents as of December 31, 2020, December 31, 2019 and 2018 pending payment of benefits.

PBOP Plan	**Target Allocation**	**Actual Allocation at December 31,**		
	2021	**2020**	**2019**	**2018**
Equity Funds	55%	**55%**	56%	53%
Debt Funds	45%	**45%**	44%	47%
Total		**100%**	100%	100%

UNITIL ENERGY SYSTEMS, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

The combination of these target allocations and expected returns resulted in the overall assumed long-term rate of return of 7.40% for 2020. The Company evaluates the actuarial assumptions, including the expected rate of return, at least annually. The desired investment objective is a long-term rate of return on assets that is approximately 5 – 6% greater than the assumed rate of inflation as measured by the Consumer Price Index. The target rate of return for the Plans has been based upon an analysis of historical returns supplemented with an economic and structural review for each asset class.

Following is a description of the valuation methodologies used for assets measured at fair value. There have been no changes in the methodologies used at December 31, 2020 and 2019. See the "Fair Value" section of Note 1 (Summary of Significant Accounting Policies) for a discussion of the Company's fair value accounting policy.

Equity and Fixed Income Funds
These investments are valued based on quoted prices from active markets. These securities are categorized in Level 1 as they are actively traded and no valuation adjustments have been applied.

Cash Equivalents
These investments are valued at cost, which approximates fair value, and are categorized in Level 1.

Real Estate Fund
These investments are valued at net asset value (NAV) per unit based on a combination of market- and income-based models utilizing market discount rates, projected cash flows and the estimated value into perpetuity. In accordance with FASB Codification Topic 820, "Fair Value Measurement", these investments have not been classified in the fair value hierarchy. The fair value amounts presented in the following tables for the Real Estate Fund are intended to permit reconciliation of the fair value hierarchy to the "Plan Assets at End of Year" line item shown in the "Change in Plan Assets" table above.

UNITIL ENERGY SYSTEMS, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

Assets measured at fair value on a recurring basis for the Pension Plan as of December 31, 2020 and 2019 are as follows ($000's):

		Fair Value Measurements at Reporting Date Using		
Description	**Balance as of December 31,**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
2020				
Pension Plan Assets:				
Equity Funds	$ 30,815	$ 30,815	$ ---	$ ---
Fixed Income Funds	19,537	19,537	---	---
Total Mutual Funds	50,352	50,352	---	---
Cash Equivalents	494	494	---	---
Total Assets in the Fair Value Hierarchy	$ 50,846	$ 50,846	$ ---	$ ---
Real Estate Fund – Measured at Net Asset Value	2,250			
Total Assets	$ 53,096			
2019				
Pension Plan Assets:				
Equity Funds	$ 27,237	$ 27,237	$ ---	$ ---
Fixed Income Funds	17,795	17,795	---	---
Total Mutual Funds	45,032	45,032	---	---
Cash Equivalents	297	297	---	---
Total Assets in the Fair Value Hierarchy	$ 45,329	$ 45,329	$ ---	$ ---
Real Estate Fund – Measured at Net Asset Value	4,422			
Total Assets	$ 49,751			

UNITIL ENERGY SYSTEMS, INC.
NOTES TO FINANCIAL STATEMENTS
December 31, 2020, 2019 and 2018

Assets measured at fair value on a recurring basis for the PBOP Plan as of December 31, 2020 and 2019 are as follows ($000's):

	Fair Value Measurements at Reporting Date Using			
Description	Balance as of December 31,	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
2020				
PBOP Plan Assets:				
Mutual Funds:				
Fixed Income Funds	$ **4,014**	$ **4,014**	$ ---	$ ---
Equity Funds	**4,946**	**4,946**	---	---
Total Assets	$ **8,960**	$ **8,960**	$ ---	$ ---
2019				
PBOP Plan Assets:				
Mutual Funds:				
Fixed Income Funds	$ 3,356	$ 3,356	$ ---	$ ---
Equity Funds	4,345	4,345	---	---
Total Assets	$ 7,701	$ 7,701	$ ---	$ ---

Employee 401(k) Tax Deferred Savings Plan - The Company co-sponsors the Unitil Corporation Tax Deferred Savings and Investment Plan (the 401(k) Plan) under Section 401(k) of the Internal Revenue Code and covering substantially all of the Company's employees. Participants may elect to defer current compensation by contributing to the plan. Employees may direct, at their sole discretion, the investment of their savings plan balances (both the employer and employee portions) into a variety of investment options, including a Company common stock fund.

The Company's share of contributions to the 401(k) Plan was $779,500, $744,300 and $686,000 for the years ended December 31, 2020, 2019, and 2018, respectively.

In accordance with PUC 1604.01(a), please provide:

(14) A list of officers and directors of the utility and their full compensation for each of the last two years, detailing base compensation, bonuses and incentive plans.

Response:

Attachment 1 **REDACTED** lists the officers of Unitil Energy Systems, Inc. ("UES"). These officers receive no direct compensation from UES for their services. Rather, each officer of UES is an employee of Unitil Service Corp. ("Unitil Service"), and their entire compensation for all job responsibilities is through Unitil Service. Accordingly, the annual compensation listed on Attachment 1 for each officer in 2019 and 2020 is the *total* amount received from Unitil Service.

All officers' compensation is allocated to Unitil Corporation's subsidiaries through the Unitil Service billing system. Accordingly, approximately 28.17% of the total compensation was allocated to UES in 2019, and approximately 27.50% was allocated to UES in 2020.

The compensation listed for officers Meissner, Black, Brock, Collin, and Vaughan is reported in Unitil Corporation's 2021 Proxy Statement, filed with the federal Securities and Exchange Commission. The amounts listed for officers Diggins, Eisfeller, Furino, Letourneau and Whitney are not reported, and is non-public, confidential information. A Motion for Confidential Treatment of this information, pursuant to Puc 203.08, is included with UES's Petition.

Attachment 2 lists the directors of UES and the total annual compensation for each person in 2019 and 2020. As is the case with UES's officers, UES's Board of Directors receive no direct compensation from UES. All Directors' compensation in 2019 and 2020 was allocated to Unitil Corporation's subsidiaries through the Unitil Service billing system, with amounts allocated to UES using the same percentages as indicated above for the allocation of compensation for UES's officers.

PUC 1604.01(a) - 14 Attachment 1

PUC 1604.01(a) - 14 Att 1

REDACTED

Unitil Energy Systems, Inc.

Officers Compensation

Test Year		**2019**			**2020**		
Name	**Title**	**Base Salary**	**Incentive Cash**	**Restricted Stock**	**Base Salary**	**Incentive Cash**	**Restricted Stock**
Meissner	President	$ 572,000.00	$ 459,677.00	$ 938,737.48	$ 597,740.00	$ 527,956.00	$ 998,567.35
Black	Sr. VP	$ 292,600.00	$ 139,732.00	$ 478,707.57	$ 301,378.00	$ 145,422.00	$ 126,721.74
Brock [1]	VP and Controller / Sr. VP	$ 264,546.00	$ 115,144.00	$ 119,852.61	$ 286,000.00	$ 131,479.00	$ 126,721.74
Collin [2]	Sr. VP	$ 122,667.00	$ 232,943.00	$ 215,086.85	N/A	N/A	N/A
Diggins [3]	Treasurer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Eisfeller	VP	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hevert [4]	Sr. VP	N/A	N/A	N/A	$ 153,910.00	N/A	N/A
Hurstak [5]	Controller	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Furino	VP	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Letourneau	VP	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Vaughan [6]	*Sr. VP & Treasurer*	*$ 330,000.00*	*$ -*	*N/A*	*$ 339,900.00*	*$ 210,870.00*	*$ 62,727.53*
Whitney	Secretary	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

1 - Brock - VP & Controller in 2019; Sr VP in 2020
2 - Collin - Retired in May 2019
3 - Diggins - Treasurer in 2020
4 - Hevert - Sr. VP in July 2020; no Incentive Cash or Restricted Stock Award
5 - Hurstak - Controller in March 2020; no Incentive Cash or Restricted Stock Award
6 - Vaughan - Sr VP & Treasurer in Jan 2019; Resigned in March 2020

PUC 1604.01(a) - 14 Attachment 2

PUC 1604.01(a) - 14 - Attachment 2

Unitil Energy Systems, Inc.

Directors' Compensation

Test Year	2019			2020		
Name	Cash Retainer	Common Stock	Restricted Stock Units	Cash Retainer	Common Stock	Restricted Stock Units
Robert V. Antonucci [1]	$ 77,000	$ -	$ 69,977	$ 40,500	$ 23,780	$ -
Winfield S. Brown [2]	N/A	N/A	N/A	$ 76,000	$ 69,973	$ -
David P. Brownell [1]	$ 77,000	$ -	$ 69,977	$ 40,500	$ 23,780	$ -
Mark H. Collin	$ 44,388	$ 46,893	$ -	$ 73,000	$ 69,973	$ -
Lisa Crutchfield	$ 88,500	$ -	$ 69,977	$ 90,500	$ -	$ 69,961
Albert H. Elfner, III [1]	$ 73,000	$ -	$ 69,977	$ 39,500	$ 23,780	$ -
Suzanne Foster	$ 71,000	$ 69,958	$ -	$ 76,000	$ 69,973	$ -
Edward F. Godfrey	$ 74,500	$ -	$ 69,977	$ 80,500	$ 69,973	$ -
Michael B. Green	$ 105,500	$ -	$ 69,977	$ 110,500	$ -	$ 69,961
Thomas P. Meissner, Jr. [3]	N/A	N/A	N/A	N/A	N/A	N/A
Eben S. Moulton	$ 72,000	$ -	$ 69,977	$ 79,000	$ -	$ 69,961
M. Brian O'Shaughnessy [1]	$ 71,000	$ -	$ 69,977	$ 37,500	$ 23,780	$ -
Justine Vogel	$ 71,000	$ 69,958	$ -	$ 76,000	$ 69,973	$ -
David A. Whiteley	$ 88,500	$ -	$ 69,977	$ 90,500	$ 69,973	$ -

[1] Antonucci, Brownell, Elfner, and O'Shaughnessy retired from the Board in April 2020.

[2] Winfield S. Brown joined the Board in January 2020.

[3] Employee directors are not compensated for board service.

(15) Copies of all officer and executive incentive plans.

Response:

Incentive plans in which officers and executives participate include the following:

Attachment 1 - Management Incentive Plan
Attachment 2 - Unitil Corporation Second Amended and Restated 2003 Stock Plan

UNITIL CORPORATION MANAGEMENT INCENTIVE PLAN
(amended and restated as of June 5, 2013)

The purpose of the Unitil Corporation Management Incentive Plan (the "Plan") is to provide key management employees of Unitil Corporation and its subsidiaries identified on Exhibit A attached hereto (collectively, the "Corporation") with significant incentives related to the performance of the Corporation and thereby to motivate them to maximize their efforts on the Corporation's behalf. The Plan is further intended to provide the Corporation's key management employees with competitive levels of total compensation when considered with their base salaries.

I. PARTICIPATION

Key management employees of the Corporation who are selected by the Compensation Committee (the "Committee") of the Corporation's Board of Directors (the "Board") for participation shall participate in the Plan (each such participating key management employee, a "Participant") for the applicable Performance Period(s) (as defined below). Each Participant in the Plan for a Performance Period shall be notified of such Participant's selection, such Participant's Target Incentive Award (as defined below) and the specific Performance Objectives and Performance Standards (each as defined below) upon which such Participant's Incentive Awards (as defined below), if any, shall be based. The Participants in the Plan for the applicable Performance Period shall be documented.

II. TARGET INCENTIVE AWARD

The Committee shall establish an individual targeted award (the "Target Incentive Award") under the Plan for each Participant for each Performance Period, expressed as a percentage of the Participant's base salary (prior to reduction under the Corporation's 401(k) retirement plan or cafeteria plan, "Base Salary") earned during the applicable Performance Period. The Target Incentive Awards for all Participants for the applicable Performance Period shall be documented.

III. PERFORMANCE PERIOD

The Performance Period is the period during which performance will be measured for determining the amounts of Participants' awards under the Plan ("Incentive Awards"). The Performance Period for the Plan shall be the calendar year.

IV. PERFORMANCE OBJECTIVES

Prior to the beginning of each Performance Period, or as soon thereafter as practicable, the Committee shall establish, based in part upon the recommendations of the Corporation's Chief Executive Officer (the "CEO"), objectives for the performance of the Corporation for the next following Performance Period, deemed necessary for the Corporation to achieve its strategic plans ("Performance Objectives"), the achievement of which or failure to achieve will result in the payment of Incentive Awards, as described in Section VIII, Determination of Incentive Awards. The Performance Objectives for the applicable Performance Period shall be documented.

V. PERCENTAGE WEIGHTING

Coincident with the establishment of the Performance Objectives for a particular Performance Period, the Committee shall, based in part upon the recommendations of the CEO, determine the relevant weights (the "Percentage Weightings") to be assigned to each of the Performance Objectives established for such Period, based on the relative impact of each Performance Objective on the Corporation's performance. The Percentage Weightings for the applicable Performance Period shall be documented.

VI. PERFORMANCE STANDARDS

Prior to the beginning of each Performance Period, or as soon thereafter as practicable, the Committee shall, based in part upon the recommendations of the CEO, establish the Performance Standards for each Performance Objective. The Performance Standards for the current Performance Period shall be documented. Performance Standards shall be set for the following three levels of achievement - "Threshold," "Target" and "Maximum."

A. **Threshold:** The minimum level of performance required for an Incentive Award to be paid. No Incentive Award shall be paid for performance below this level. Achievement of the Threshold level shall result in a payment equal to 50% of the amount of the Target Incentive Award for the Performance Objective, as adjusted by the applicable Percentage Weighting.

B. **Target:** The expected level of performance required, for which an Incentive Award in an amount equal to 100% of the Target Incentive Award shall be paid for the Performance Objective, as adjusted by the applicable Percentage Weighting.

C. **Maximum:** The maximum level of performance, for which an Incentive Award in an amount equal to 150% of the amount of the Target Incentive Award shall be paid for the Performance Objective, as adjusted by the applicable Percentage Weighting. Achievement of a result greater than the Maximum level shall not increase the amount of the Incentive Award.

VII. CONTROLLING THRESHOLD(S)

The Committee may, based in part upon the recommendations of the CEO, establish minimum organization performance level(s) for each Performance Period ("Controlling Threshold(s)") that must be satisfied by the Corporation for Incentive Awards to be paid; provided, however, that a Controlling Threshold need not be established for any particular Performance Period. The Controlling Threshold(s) for the applicable Performance Period shall be documented.

VIII. DETERMINATION OF INCENTIVE AWARDS

As soon as practicable following the completion of a Performance Period, the Committee shall determine the degree of satisfaction of the Performance Objectives and the amounts of the Incentive Awards payable in accordance with the Plan, if any. The amount of the Incentive Award earned by each Participant shall depend upon the degree of achievement of the

Performance Standards for each Performance Objective and the Percentage Weighting assigned thereto. If an achievement level falls between the Threshold and Target levels or between the Target and Maximum levels, the Incentive Award shall be linearly extrapolated between the two levels. Award calculations will be applied to Base Salary earned during the applicable Performance Period. Subject to the payment limitations in paragraph X below and notwithstanding anything else to the contrary contained in the Plan, the Committee shall have absolute discretion with respect to the payment of Incentive Awards, including but not limited to the amount to be paid and whether or not payment will be made, on the basis of business conditions.

IX. PLAN ADMINISTRATION

The Plan shall be administered by the Committee. The Committee shall, in its sole discretion, interpret the Plan, prescribe, amend and rescind any rules and regulations necessary or appropriate for administration of the Plan and make such other determinations and take such other actions as it deems necessary or advisable for such purposes. Any interpretation, determination or other action made or taken by the Committee shall be final, binding, and conclusive. The Committee may rely upon the advice, counsel, and assistance of the CEO in performing its duties under the Plan.

X. PAYMENT OF INCENTIVE AWARDS

Payment of each Participant's Incentive Award shall be made as soon as practicable following the end of the applicable Performance Period, but not prior to January 1 or later than March 15 of the calendar year following the Performance Period (the "Incentive Award Payment Date"); provided, however, that notwithstanding anything to the contrary contained in the Plan, no Incentive Award shall be paid to any individual who is not employed by the Corporation on the applicable Incentive Award Payment Date, unless due to the individual's death, disability (entitlement to benefits under the Corporation's Long-Term Disability Plan, "Disability") or retirement at or after attaining age 55. Incentive Award payments made due to the Participant's death, Disability or retirement at or after attaining age 55 shall be made on the applicable Incentive Award Payment Date. All Incentive Awards shall be paid in a lump sum in cash, less any amounts required for federal, state and local income and payroll tax withholdings.

XI. DISCIPLINARY ACTION

Notwithstanding anything to the contrary contained in the Plan, a Participant whose performance rating for a Performance Period is "Does Not Meet Expectations" (pursuant to the Corporation's Salary Administration Policy) shall not receive an Incentive Award for such Performance Period.

XII. TERMINATION OF EMPLOYMENT

If a Participant ceases to be employed by the Corporation (a) by reason of his death, Disability or retirement at or after attaining age 55, the Participant's Incentive Award for the Performance Period in which his employment terminates shall be calculated using the Participant's Base Salary earned prior to his termination of employment, or (b) other than by reason of his death, Disability or retirement at or after attaining age 55, the Participant's Incentive Award for the Performance Period in which his employment terminates shall be forfeited.

XIII. FUNDING

No funds shall be set aside or reserved for payment of Incentive Awards under the Plan, and all obligations of the Corporation under the Plan shall be unfunded and shall be paid from the general assets of the Corporation.

XIV. NOT EXCLUSIVE METHOD OF INCENTIVE

The Plan shall not be deemed to be an exclusive method of providing incentive compensation for employees of the Corporation nor shall it preclude the Board from authorizing or approving other forms of incentive compensation therefor.

XV. NO RIGHT TO CONTINUED PARTICIPATION

Participation in the Plan by an employee in any Performance Period shall not be held or construed to confer upon such employee the right to participate in the Plan in any subsequent Performance Period.

XVI. NO RIGHT TO CONTINUED EMPLOYMENT

None of the establishment of the Plan, participation in the Plan by a Participant, the payment of any Incentive Award hereunder or any other action pursuant to the Plan shall be held or construed to confer upon any employee the right to continue in the employ of the Corporation or affect any right which the Corporation may have to terminate at will the employment thereof.

XVII. NONTRANSFERABILITY OF AWARDS

Except by operation of the laws of descent and distribution, no amount payable at any time under the Plan shall be subject to alienation by anticipation, sale, transfer, assignment, bankruptcy, pledge, attachment, charge or encumbrance of any kind nor in any manner be subject to the debts or liabilities of any person, and any attempt to so alienate or subject any such amount shall be void.

XVIII. AMENDMENT AND TERMINATION

The Board may amend or terminate the Plan at any time; provided, however, that no amendment or termination of the Plan shall adversely affect the entitlement of a Participant to payment of any Incentive Award which has been determined by the Committee prior to such amendment or termination, although the Board may amend or terminate the rights of any Participant under the Plan at any time prior to the determination of the amount of the Incentive Award to be paid thereto for a Performance Period.

XIX. EFFECTIVE DATE

The Plan shall be effective June 5, 2013 and shall continue in effect until terminated by the Board.

Exhibit A
Participating Subsidiaries

Unitil Energy Systems, Inc.

Fitchburg Gas and Electric Light Company

Unitil Service Corp.

Usource LLC

Northern Utilities, Inc.

Granite State Gas Transmission, Inc.

Unitil Corporation
Second Amended and Restated
2003 Stock Plan

Effective: April 19, 2012

Unitil Corporation
Second Amended and Restated
2003 Stock Plan

ARTICLE 1

Establishment, Objectives, and Duration

1.1 Establishment of the Plan. Unitil Corporation, a corporation organized and existing under New Hampshire law (the "Company"), hereby establishes an incentive compensation plan to be known as the "Unitil Corporation Second Amended and Restated 2003 Stock Plan" (hereinafter referred to as the "Plan"). The Plan permits the grant of Shares and Restricted Stock Units. The Plan first became effective on January 1, 2003 and was previously known as the "Unitil Corporation 2003 Restricted Stock Plan." On March 24, 2011, the Plan was amended and restated to permit the granting of Restricted Stock Units, to change the name of the Plan to the "Unitil Corporation Amended and Restated 2003 Stock Plan," and to make other non-material revisions. The Plan, as further amended, restated and renamed, will become effective on April 19, 2012 if approved by the Company's shareholders at the Company's 2012 Annual Meeting of Shareholders. The Plan shall remain in effect as provided in Section 1.3 hereof.

1.2 Objectives of the Plan. The objectives of the Plan are to optimize the profitability and growth of the Company through incentives which are consistent with the Company's goals and which link the personal interests of Participants to those of the Company's shareholders; to provide Participants with an incentive for excellence in individual performance; and to promote teamwork among Participants.

1.3 Duration of the Plan. The Plan shall remain in effect, subject to the right of the Board to amend or terminate the Plan at any time pursuant to Article 14 hereof, until all Shares subject to it shall have been purchased or acquired according to the Plan's provisions.

ARTICLE 2

Definitions

Whenever used in the Plan, the following terms shall have the meanings set forth below, and, when the meaning is intended, the initial letter of the word shall be capitalized:

2.1 "Affiliate" means any parent or subsidiary of the Company which meets the requirements of Section 424 of the Code.

2.2 "Award" means, individually or collectively, an award under this Plan of Shares or Restricted Stock Units.

2.3 "Award Agreement" means an agreement entered into by the Company and each Participant setting forth the terms and provisions applicable to Awards made under the Plan.

2.4 "Board" means the Board of Directors of the Company.

2.5 "Change in Control" means the satisfaction of any one or more of the following conditions (and the "Change in Control" shall be deemed to have occurred as of the first day that any one or more of the following conditions shall have been satisfied):

(a) the Company receives a report on Schedule 13D filed with the Securities and Exchange Commission pursuant to Rule 13(d) of the Exchange Act, disclosing that any person, group, corporation or other entity is the beneficial owner, directly or indirectly, of 25% or more of the outstanding Shares;

(b) any "person" (as such term is used in Section 13(d) of the Exchange Act), group, corporation or other entity other than the Company or a wholly-owned subsidiary of the Company, purchases Shares pursuant to a tender offer or exchange offer to acquire any Shares (or securities convertible into Shares) for cash, securities or any other consideration, provided that after consummation of the offer, the person, group, corporation or other entity in question is the "beneficial owner" (as such term is defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of 25% or more of the outstanding Shares (calculated as provided in paragraph (d) of Rule 13d-3 under the Exchange Act in the case of rights to acquire Shares);

(c) consummation of a transaction which involves (1) any consolidation or merger of the Company in which the Company is not the continuing or surviving corporation, or pursuant to which Shares of the Company would be converted into cash, securities or other property (except where the Company's shareholders before such transaction will be the owners of more than 75% of all classes of voting securities of the surviving entity); or (2) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all or substantially all the assets of the Company.

(d) there shall have been a change in a majority of the members of the Board within a 25-month period, unless the election or nomination for election by the Company's shareholders of each new director was approved by the vote of at least two-thirds of the directors then still in office who were in office at the beginning of the 25-month period.

2.6 "Code" means the Internal Revenue Code of 1986, as amended from time to time.

2.7 "Committee" means (i) the Compensation Committee of the Board, as specified in Article 3 herein, or (ii) such other Committee appointed by the Board to administer the Plan (or aspects thereof) with respect to grants of Awards except (a) as may be prohibited by applicable law, the Company's Articles of Incorporation or the

Company's By-Laws or (b) as may conflict with the authority that the Board has delegated to another Committee appointed by the Board.

2.8 "Company" means Unitil Corporation, a corporation organized and existing under New Hampshire law, and any successor thereto as provided in Article 17 herein.

2.9 "Consultant" means an independent contractor who is performing consulting services for one or more entities in the Group and who is not an employee of any entity in the Group.

2.10 "Director" means a member of the Board or a member of the board of directors of an Affiliate.

2.11 "Director Participant" means a Participant who receives an Award for his or her services as a Director.

2.12 "Disability" shall have the meaning ascribed to such term in the long-term disability plan maintained by the Company, or if no such plan exists, at the discretion of the Committee.

2.13 "Dividend Equivalents" shall have the meaning ascribed to such term in Section 7.5 hereof.

2.14 "Employee" means any employee of the Group, including any employees who are also Directors.

2.15 "Exchange Act" means the Securities Exchange Act of 1934, as amended from time to time, or any successor act thereto.

2.16 "Fair Market Value" means as of any date, the closing price based upon composite transactions on a national stock exchange for one Share or, if no sales of Shares have taken place on such date, the closing price on the most recent date on which selling prices were quoted. In the event the Company's Shares are no longer traded on a national stock exchange, Fair Market Value shall be determined in good faith by the Committee.

2.17 "Group" means the Company and its Affiliates.

2.18 "Named Executive Officer" means a Participant who, as of the date of vesting of an Award, is one of the group of "covered employees," as defined in the regulations promulgated under Code Section 162(m), or any successor section.

2.19 "Nonemployee Director" shall have the meaning ascribed to such term in Rule 16b-3 of the Exchange Act.

2.20 "Outside Director" shall have the meaning ascribed to such term under the regulations promulgated with respect to Code Section 162(m).

2.21 "Participant" means a current or former Employee, Director, or Consultant who has outstanding an Award granted under the Plan.

2.22 "Performance-Based Exception" means the performance-based exception from the tax deductibility limitations of Code Section 162(m).

2.23 "Period(s) of Restriction" means the period (or periods) during which the transfer of Shares or Restricted Stock Units are limited in some way (based on the passage of time, the achievement of performance goals, or upon the occurrence of other events as determined by the Committee, at its discretion), and the Shares or Restricted Stock Units are subject to a substantial risk of forfeiture.

2.24 "Plan" shall have the meaning ascribed to such term in Section 1.1 hereof.

2.25 "Restricted Stock" or **"Restricted Share"** means an Award of Shares granted to a Participant pursuant to Article 6 herein subject to a Period(s) of Restriction.

2.26 "Restricted Stock Unit" means an Award granted to a Participant pursuant to Article 7 herein.

2.27 "RSU Election" shall have the meaning ascribed to such term in section 7.1 hereof.

2.28 "Shares" means the shares of common stock (no par value) of the Company.

2.29 "Termination of Service" means, (i) if an Employee, termination of employment with all entities in the Group, (ii) if a Director, termination of service on the Board and the board of directors of any Affiliate, as applicable, and (iii) if a Consultant, termination of the consulting relationship with all entities in the Group; provided, however, that if a Participant serves the Group in more than one of the above capacities, Termination of Service shall mean termination of service in all such capacities; provided, however, that with respect to any Restricted Stock Units that constitute deferred compensation for purposes of Code Section 409A, the term Termination of Service shall mean "separation from service," as that term is used in Code Section 409A.

ARTICLE 3

Administration

3.1 The Committee. The Plan shall be administered by the Committee. To the extent the Company deems it to be necessary or desirable with respect to any Awards made hereunder, the members of the Committee may be limited to Nonemployee Directors or Outside Directors, who shall be appointed from time to time by, and shall serve at the discretion of, the Board.

3.2 Authority of the Committee. Except as limited by law or by the Articles of Incorporation or the By-laws of the Company, and subject to the provisions herein, the

Committee shall have full power to select the persons who shall participate in the Plan; determine the sizes of Awards; determine the terms and conditions of Awards in a manner consistent with the Plan; construe and interpret the Plan and any agreement or instrument entered into under the Plan as they apply to Participants; establish, amend, or waive rules and regulations for the Plan's administration as they apply to Participants; and (subject to the provisions of Article 14 herein) amend the terms and conditions of any outstanding Award to the extent such terms and conditions are within the discretion of the Committee as provided in the Plan. Further, the Committee shall make all other determinations which may be necessary or advisable for the administration of the Plan. As permitted by law, the Committee may delegate its authority as identified herein.

3.3 Decisions Binding. All determinations and decisions made by the Committee pursuant to the provisions of the Plan and all related orders and resolutions of the Board shall be final, conclusive and binding on all persons, including the Company, its shareholders, Affiliates, Participants, and their estates and beneficiaries.

ARTICLE 4

Shares Subject to the Plan and Maximum Awards

4.1 Number of Shares Available for Grants.

(a) Subject to adjustment as provided in Section 4.2, the maximum number of Shares available for Awards to Participants under the Plan shall be 677,500 Shares. The 677,500 Shares referred to in the immediately preceding sentence includes 177,500 Shares initially made available for Awards to Participants under the Plan and 500,000 Shares added to the Plan as of April 19, 2012. To the extent all or any portion of an Award expires before vesting, is forfeited, or is paid in cash, the Shares subject to such portion of the Award shall again be available for issuance under the Plan. For avoidance of doubt, if Shares are returned to the Company in satisfaction of taxes relating to a Restricted Stock Award, such issued Shares shall not become available again under the Plan.

(b) The maximum aggregate number of Shares or Restricted Stock Units that may be granted in any one calendar year to any one Participant shall be 20,000, subject to adjustment in accordance with Section 4.2.

4.2 Adjustments in Authorized Shares. In the event of an equity restructuring (within the meaning of Financial Accounting Standards Board Accounting Standards Codification Topic 718, Stock Compensation) affecting the Shares, such as a stock dividend, stock split, spin off, rights offering, or recapitalization through a large, nonrecurring cash dividend, the Committee shall authorize and make an equitable adjustment to the number and kind of Shares that may be delivered pursuant to Section 4.1 and, in addition, may authorize and make an equitable adjustment to the Award limit set forth in Section 4.1(b). In the event of any other change in corporate capitalization, such as a merger, consolidation, reorganization or partial or complete liquidation of the Company, the Committee may, in its sole discretion, authorize and make such proportionate adjustments, if any, as the Committee shall deem appropriate to prevent dilution or enlargement of rights, including, without limitation, an adjustment in the maximum number and kind of Shares or Restricted Stock Units that may be delivered pursuant to Section 4.1 and in the Award limit set forth in Section 4.1(b). The number of Shares or Restricted Stock Units subject to any Award shall always be rounded to the nearest whole number, with one-half (1/2) of a share rounded up to the next higher number.

ARTICLE 5

Eligibility and Participation

5.1 Eligibility. Persons eligible to participate in this Plan include all Employees, Directors and Consultants of the Group.

5.2 Actual Participation. Subject to the provisions of the Plan, the Committee may, from time to time, select from all eligible Employees, Directors and Consultants those to whom Awards shall be made and shall determine the nature and amount of each Award.

ARTICLE 6

Stock Awards

6.1 Grant of Stock Awards. Subject to the terms and provisions of the Plan, the Committee, at any time and from time to time, may grant Shares to Participants in such amounts as the Committee shall determine and subject to any restrictions the Committee may deem appropriate.

6.2 Stock Award Agreement. Each grant of Shares shall be evidenced by an Award Agreement that shall specify the Period(s) of Restriction, if any, the number of Shares granted, and such other provisions as the Committee shall determine.

6.3 Transferability. Except as provided in this Article 6, the Shares granted herein may not be sold, transferred, pledged, assigned or otherwise alienated or hypothecated until the end of any applicable Period(s) of Restriction established by the Committee and specified in the Award Agreement.

6.4 Restrictions.

(a) Subject to the terms hereof, the Committee shall impose such conditions and/or restrictions on any Shares granted pursuant to the Plan as it may deem advisable and as are expressly set forth in the Award Agreement including, without limitation, a requirement that Participants pay a stipulated purchase price for each Share, restrictions based upon the achievement of specific performance goals (Company-wide, divisional, and/or individual), time-based restrictions, and/or restrictions under applicable federal or state securities laws. For purposes of Awards granted under this Article 6, the period(s) that the Shares are subject to such conditions and/or restrictions shall be referred to as the “Period(s) of Restriction.”

(b) The Participant shall execute appropriate stock powers in blank and such other documents as the Committee shall prescribe.

(c) Subject to restrictions under applicable law or as may be imposed by the Company, Shares covered by each Award made under the Plan shall become freely transferable by the Participant after the last day of any applicable Period(s) of Restriction.

6.5 Voting Rights. During any Period(s) of Restriction, subject to any limitations imposed under the By-laws of the Company, Participants holding Shares granted hereunder may exercise full voting rights with respect to those Shares.

6.6 Dividends and Other Distributions. During any Period(s) of Restriction, Participants holding Shares granted hereunder may be credited with regular dividends paid with respect to the underlying Shares while they are so held. The Committee may apply any restrictions to the dividends that the Committee deems appropriate and as are expressly set forth in the Award Agreement. Without limiting the generality of the preceding sentence, if the grant or vesting of Shares granted to a Named Executive Officer is designed to comply with the requirements of the Performance-Based Exception, the Committee may apply any restrictions it deems appropriate to the payment of dividends declared with respect to such Shares, such that the dividends and/or the Shares maintain eligibility for the Performance-Based Exception.

ARTICLE 7

Restricted Stock Units

7.1 Grant of Restricted Stock Units. Subject to the terms and provisions of the Plan (a) the Committee, at any time and from time to time, may grant Restricted Stock Units to Participants in such amounts as the Committee shall determine and (b) to the extent permitted by the Committee, Director Participants may elect to receive Restricted Stock Units in lieu of Shares (an “RSU Election”) that such Director Participant otherwise would receive for services on the Board. Each Restricted Stock Unit Award shall be evidenced by an Award Agreement that shall specify the Period(s) of Restriction/vesting schedule (if any), the number of Restricted Share Units granted, and such other provisions as the Committee shall determine. A Restricted Stock Unit is a notional unit of measurement denominated in Shares (*i.e.*, one Restricted Stock Unit is equivalent in value to one Share), which represents an unfunded, unsecured right to receive Shares or a cash amount equal to the Fair Market Value of the Shares that would have been received (as specified in the applicable RSU Agreement) on the terms and conditions set forth herein and in the applicable RSU Agreement.

7.2 RSU Elections. Any RSU Election will be made in the manner determined by the Committee. Notwithstanding the foregoing, an RSU Election shall only be effective if (a) the RSU Election was made in the calendar year prior to the calendar year in which the services to which the Shares and Restricted Stock Units relate are performed, (b) the RSU Election was made within 30 days of a Director Participant first becoming eligible to participate in the Plan and such RSU Election is limited to compensation earned following the date of such election, or (c) the Committee determined the RSU Election otherwise constitutes a compliant deferral election under Code Section 409A. Once a Director Participant makes an RSU Election, such election shall remain in place until revoked or changed by the Director Participant in accordance with procedures determined by the Committee. Any such revocation or change will only be effective with respect to Shares and Restricted Stock Units relating to service in calendar years following such revocation or change, unless otherwise provided by the Committee.

7.3 Vesting. The Committee shall, in its discretion, determine any vesting requirements with respect to a Restricted Stock Unit Award, which shall be set forth in the Award Agreement. The requirements for vesting of a Restricted Stock Unit Award may be based on the continued service of the Participant for a specified time period (or periods) and/or on the attainment of a specified performance goal (or goals) established by the Committee in its discretion. A Restricted Stock Unit Award may also be granted on a fully vested basis, with a deferred payment date as may be determined by the Committee or elected by the Participant in accordance with the rules established by the Committee.

7.4 Settlement of Restricted Stock Units. Restricted Stock Units shall be settled (*i.e.*, paid out) at the time or times determined by the Committee and set forth in the Award Agreement, which may be upon or following the vesting of the Award. Restricted Stock Units that constitute deferred compensation for purposes of Code Section 409A shall only be settled on dates or events that comply with Code Section 409A. If Restricted Stock Units are settled in cash, the payment with respect to each Restricted Stock Unit shall be determined by reference to the Fair Market Value of one Share on the day immediately prior to the settlement date. Restricted Stock Unit Award Agreements may provide for payment to be made in cash or in Shares, or in a combination thereof.

7.5 Dividend Equivalents. Restricted Stock Units may be granted, at the discretion of the Committee, with or without the right to receive Dividend Equivalents with respect to the Restricted Stock Units. A Dividend Equivalent is an unfunded, unsecured right to receive (or be credited with) an amount equal to the regular cash dividend payments (if any) the Participant would have been entitled to had he or she held the number of Shares underlying the Restricted Stock Units on the record date of any regular cash dividend on the Shares. The Committee may apply any terms, restrictions or conditions on the Dividend Equivalents as it deems appropriate (including, without limitation, deferring payment of the Dividend Equivalents until the related Restricted Stock Units are settled or converting Dividend Equivalents to additional Restricted Stock Units). Any such terms, restrictions or conditions shall be set forth in the Restricted Stock Unit Award Agreement.

7.6 No Rights as Stockholder. The Participant shall not have any voting or other rights as a stockholder with respect to the Shares underlying Restricted Stock Units until such time as Shares may be delivered to the Participant pursuant to the terms of the Award.

ARTICLE 8

Termination of Service

Each Award Agreement shall set forth the effect that Termination of Service shall have upon that Award. Such provisions shall be determined in the sole discretion of the Committee, need not be uniform among all Awards issued pursuant to the Plan, and may reflect distinctions based on the reasons for Termination of Service; provided, however, that the following shall automatically apply to the extent different provisions are not expressly set forth in a Participant's Award Agreement:

(a) Upon a Termination of Service for any reason other than death, retirement or Disability, all unvested Restricted Shares shall be forfeited as of the termination date.

(b) Upon a Termination of Service as a result of the Participant's death, retirement or Disability, all unvested Restricted Shares shall vest as of the termination date.

ARTICLE 9

Restrictions on Shares

All Shares issued pursuant to Awards granted hereunder, and a Participant's right to receive Shares upon vesting or settlement of an Award, shall be subject to all applicable restrictions contained in the Company's By-laws, shareholders agreement or insider trading policy, and any other restrictions imposed by the Committee, including, without limitation, restrictions under applicable securities laws, under the requirements of any stock exchange or market upon which such Shares are then listed and/or traded, and restrictions under any blue sky or state securities laws applicable to such Shares.

ARTICLE 10

Performance Measures

If an Award is subject to Code Section 162(m) and the Committee determines that such Award should be designed to comply with the Performance-Based Exception, the performance measure(s), the attainment of which determine the degree of vesting, to be used for purposes of such Awards shall be chosen from among earnings per share, economic value added, market share (actual or targeted growth), net income (before or after taxes), operating income, return on assets (actual or targeted growth), return on capital (actual or targeted growth), return on equity (actual or targeted growth), return on investment (actual or targeted growth), revenue (actual or targeted growth), share price, stock price growth, total shareholder return, or such other performance measures as are duly approved by the Committee and the Company's shareholders.

ARTICLE 11

Beneficiary Designation

Subject to the terms and conditions of the Plan and the applicable Award Agreement, each Participant may, from time to time, name any beneficiary or beneficiaries (who may be named contingently or successively) to whom Shares under the Plan are to be transferred in the event of the Participant's death. Each such designation shall revoke all prior designations by the same Participant, shall be in a form prescribed by the Company, and will be effective only when filed by the Participant in writing during the Participant's lifetime with the party chosen by the Company, from time to time, to administer the Plan. In the absence of any such designation, Shares shall be paid to the Participant's estate following his death.

ARTICLE 12

Rights of Participants

12.1 Continued Service. Nothing in the Plan shall:

(a) interfere with or limit in any way the right of the Company to terminate any Participant's employment, service as a Director, or service as a Consultant with the Group at any time, or

(b) confer upon any Participant any right to continue in the service of any member of the Group as an Employee, Director or Consultant.

12.2 Participation. Participation is determined by the Committee. No person shall have the right to be selected to receive an Award under the Plan, or, having been so selected, to be selected to receive a future Award.

ARTICLE 13

Change in Control

Upon the occurrence of a Change in Control, unless otherwise specifically prohibited under applicable laws, or by the rules and regulations of any governing governmental agencies or national securities exchanges, any restrictions and transfer limitations imposed on Restricted Shares shall immediately lapse and any unvested Restricted Stock Units shall immediately become vested.

ARTICLE 14

Amendment or Termination

The Board may at any time and from time to time amend or terminate the Plan or any Award hereunder in whole or in part; provided, however, that no amendment which requires shareholder approval in order for the Plan to continue to comply with any applicable tax or securities laws or regulations, or the rules of any securities exchange on which the securities of the Company are listed, shall be effective unless such amendment shall be approved by the requisite vote of shareholders of the Company entitled to vote thereon; provided further that no such amendment or termination shall adversely affect any Award hereunder without the consent of the Participant.

ARTICLE 15

Withholding

15.1 Tax Withholding. The Company shall have the right to deduct or withhold, or require a Participant to remit to the Company, an amount sufficient to satisfy any taxes required by federal, state, or local law or regulation to be withheld with respect to any taxable event arising in connection with an Award.

15.2 Share Withholding. Participants may elect, subject to the approval of the Committee, to satisfy all or part of such withholding requirement by having the Company withhold Shares having a Fair Market Value equal to the minimum statutory total tax which could be imposed on the transaction. All such elections shall be irrevocable, made in writing, signed by the Participant, and shall be subject to any restrictions or limitations that the Committee, in its sole discretion, deems appropriate.

ARTICLE 16

Indemnification

Each person who is or shall have been a member of the Committee, or of the Board, shall be indemnified and held harmless by the Company to the fullest extent permitted by applicable law against and from any loss, cost, liability, or expense that may be imposed upon or reasonably incurred by him or her in connection with or resulting from any claim, action, suit, or proceeding to which he or she may be a party or in which he or she may be involved by reason of any action taken or failure to act under the Plan and against and from any and all amounts paid by him or her in settlement thereof, with the Company's approval, or paid by him or her in satisfaction of any judgment in any such action, suit, or proceeding against him or her, provided he or she shall give the Company an opportunity, at its own expense, to handle and defend the same before he or she undertakes to handle and defend it on his or her own behalf. The foregoing right of indemnification is subject to the person having been successful in the legal proceedings or having acted in good faith and what is reasonably believed to be a lawful manner in the Company's best interests. The foregoing right of indemnification shall not be exclusive of any other rights of indemnification to which such persons may be entitled under the Company's Articles of Incorporation or Bylaws, as a matter of law, or otherwise, or any power that the Company may have to indemnify them or hold them harmless.

ARTICLE 17

Successors

All obligations of the Company under the Plan with respect to Awards granted hereunder shall be binding on any successor to the Company, whether the existence of such successor is the result of a direct or indirect purchase, merger, consolidation, or otherwise, of all or substantially all of the business and/or assets of the Company.

ARTICLE 18

Miscellaneous

18.1 Gender and Number. Except where otherwise indicated by the context, any masculine term used herein also shall include the feminine; the plural shall include the singular and the singular shall include the plural.

18.2 Severability. In the event any provision of the Plan shall be held illegal or invalid for any reason, the illegality or invalidity shall not affect the remaining parts of the Plan, and the Plan shall be construed and enforced as if the illegal or invalid provision had not been included.

18.3 Requirements of Law. The granting of Awards and the issuance of Shares under the Plan shall be subject to, and may be made contingent upon satisfaction of, all applicable laws, rules, and regulations, and to such approvals by any governmental agencies or national securities exchanges as may be required.

18.4 Governing Law. To the extent not preempted by federal law, the Plan, and all agreements hereunder, shall be construed in accordance with and governed by the laws of the state of New Hampshire.

18.5 Section 409A Compliance. To the extent applicable, it is intended that the Plan and all Awards of Restricted Stock Units comply with the requirements of Section 409A, and the Plan and the Restricted Stock Unit Award Agreements shall be interpreted accordingly.

(a) If it is determined that all or a portion of a Restricted Stock Unit Award constitutes deferred compensation for purposes of Code Section 409A, and if the Participant is a "specified employee" (as defined in Code Section 409A(a)(2)(B)(i)) at the time of the Participant's separation from service (as that term is used in Code Section 409A), then, to the extent required under Section 409A, any Shares or cash that would otherwise be paid upon the Grantee's separation from service in respect of the Restricted Stock Units (including any related Dividend Equivalents that constitute deferred compensation for purposes of Section 409A) shall instead be paid on the earlier of (i) the first business day of the sixth month following the date of the Participant's separation from service (as that term is used in Code Section 409A) or (ii) the Grantee's death.

(b) If it is determined that all or a portion of a Restricted Stock Unit Award constitutes deferred compensation for purposes of Code Section 409A, upon a Change in Control that does not constitute a “change in the ownership” or a “change in the effective control” of the Company or a “change in the ownership of a substantial portion of a corporation’s assets” (as those terms are used in Code Section 409A), the Restricted Stock Units shall vest at the time of the Change in Control to the extent so provided Article 13, but settlement of any Restricted Stock Units (and payment of any related Dividend Equivalents Payments) that constitute deferred compensation for purposes of Code Section 409A shall not be accelerated (*i.e.*, payment shall occur when it would have occurred absent the Change in Control).

(16) Lists of the amount of voting stock of the utility categorized as follows:

a. Owned by an officer or director individually;

b. Owned by the spouse or minor child of an officer or director; or

c. Controlled by the officer or director directly or indirectly.

Response:

For Unitil Energy Systems, Inc. (UES), the voting stock consists of common stock and 6% non-cumulative preferred stock. There are 131,746 shares of UES common stock outstanding, all of which are owned by Unitil Corporation. Further, no director or officer, or spouse or minor child owns or controls any of the 1,887 outstanding shares of 6% non-cumulative preferred stock individually, directly or indirectly.

(17) A list of all payments to individuals or corporations for contractual services in the test year with a description of the purpose of the contractual services, as follows:

a. For utilities with less than $10,000,000 in annual gross revenues, a list of all payments in excess of $10,000;
b. For utilities with $10,000,001 to $100,000,000 in annual gross revenues, a list of all payments in excess of $50,000;
c. For utilities with annual gross revenues in excess of $100,000,000, a list of all payments in excess of $100,000;
d. The reporting thresholds for a particular entity shall be on a cumulative basis, indicating the number of items comprising the total amount of expenditure.

Response:

a. N/A
b. N/A
c. Please see PUC 1604.01(a) – 17 Attachment 1 for a list of all payment for contractual services over $100,000.00.
d. Please see PUC 1604.01(a) – 17 Attachment 1 for the total number of items compromising the expenditure.

Unitil Energy Systems, Inc.

1604.01(a) - 20 Attachment 1
Page 1 of 1

Company	Total Expenditure	Total Items for Expenditure	Description
ADP	$ 4,052,313	121	Payroll
ADP	$ 450,503	120	FICA
ADP	$ 1,351,228	242	FICA
AECOM TECH	$ 304,669	9	Energy Efficiency
ARCA RECYCLING INC	$ 124,620	24	Energy Efficiency
ASPLUNDH TREE PA	$ 3,878,383	840	Tree Trimming
BELKNAP MERRIMACK CAP	$ 146,554	45	Electricity Assistance Program
BLACKROCK	$ 24,950,000	12	ISO Deposits
CITY OF CONCORD	$ 1,804,967	4	Property Taxes
COMMUNITY ACTION PROGRAM	$ 218,378	12	Electricity Assistance Program
EE INCENTIVES	$ 1,563,311	185	Energy Efficiency
ENERGY FEDERATION	$ 786,056	296	Rebates
ERMCO	$ 1,097,536	127	Materials and Supplies
ESTEX MANUFACTURING CO. INC.	$ 257,471	15	Materials and Supplies
G&W ELECTRIC	$ 224,280	8	Materials and Supplies
GDS ASSOCIATES INC	$ 162,552	58	Energy Efficiency
GRAYBAR ELECTRIC CO INC	$ 1,324,423	3302	Materials and Supplies
HI VOLT LINE	$ 1,511,015	688	Line Crews and Equipment
I C REED & SONS	$ 3,103,328	869	Line Crews and Equipment
INCENTIVE UES	$ 391,770	52	Energy Efficiency
LANDIS GYR	$ 105,636	27	Materials and Supplies
LUCAS TREE	$ 1,151,384	211	Tree Trimming
MERCHANTS AUTOMOTIVE	$ 177,359	100	Equipment
NATIONAL RESOURCES	$ 102,525	15	Energy Efficiency
NEW ENGLAND TRAFFIC CONTROL	$ 345,442	1057	Traffic Detail
NEWELL & CRATHERN LLC	$ 323,826	134	Energy Efficiency
NORTHERN TREE	$ 731,662	28	Tree Trimming
ODONNELL	$ 113,050	4	Line Crews and Equipment
PC CONNECTION	$ 157,352	35	IT Equipment
POWER PARTNERS LLC	$ 124,982	12	Materials and Supplies
PRISM CONSULTING	$ 275,399	19	Energy Efficiency
PRO CON INC	$ 12,172,689	30	Contractor (New Building)
QUALITY INSULATION	$ 202,327	39	Energy Efficiency
RESILIENT BUILDINGS GROUP	$ 426,387	24	Energy Efficiency
RISE ENGINEERING	$ 198,981	13	Energy Efficiency
SIEMENS INDUSTRIES	$ 142,879	32	Materials and Supplies
SOUTHERN NH SERVICES	$ 254,293	30	Energy Efficiency
SPX TRANSFORMER SOLUTIONS	$ 168,202	9	Materials and Supplies
STATE LIFE INSURANCE COMPANY	$ 8,500,000	5	Sinking Fund Payments
STATE LIFE INSURANCE COMPANY	$ 4,819,850	23	Interest on Funded Debt
STATE OF NEW HAMPSHIRE	$ 1,495,354	4	Property Taxes
STATE OF NEW HAMPSHIRE	$ 451,259	12	LI-EAP Overcollected Funds
STATE OF NEW HAMPSHIRE (PUC)	$ 755,549	4	Regulatory Assessment
STELLA JONES	$ 361,088	104	Materials and Supplies
STUART C IRBY	$ 878,136	83	Materials and Supplies
SUBSTATION ENGINEERING & DESIGN	$ 183,131	7	Materials and Supplies
TECHNIART INC	$ 125,554	6	Energy Efficiency
TFMORAN	$ 104,648	30	Professional Services
TOWN OF ATKINSON	$ 104,012	2	Property Taxes
TOWN OF BOSCAWEN	$ 245,062	2	Property Taxes
TOWN OF BOW	$ 136,462	1	Property Taxes
TOWN OF CHICHESTER	$ 122,830	2	Property Taxes
TOWN OF EAST KINGSTON	$ 139,043	2	Property Taxes
TOWN OF EXETER	$ 541,247	2	Property Taxes
TOWN OF HAMPTON	$ 473,114	2	Property Taxes
TOWN OF KENSINGTON	$ 183,222	3	Property Taxes
TOWN OF KINGSTON	$ 369,094	2	Property Taxes
TOWN OF NEWTON	$ 116,101	2	Property Taxes
TOWN OF PLAISTOW	$ 303,838	2	Property Taxes
TOWN OF STRATHAM	$ 167,105	2	Property Taxes
TOWN SEABROOK	$ 167,180	4	Property Taxes
UNITIL CORPORATION	$ 46,485	5	Taxes
UNITIL CORPORATION	$ 6,587,300	4	Dividends
UNITIL SERVICE CORP.	$ 24,887,226	24	Professional Services
US BANK	$ 323,690	6	Interest on Funded Debt
UTILITY SERVICE & ASSISTANCE	$ 781,546	115	Line Crews and Equipment
WESCO DISTRIBUTION	$ 309,678	370	Materials and Supplies
WORKFLOW INTERIORS	$ 421,280	8	Office Furniture (New Building)

(18) For non-utility operations, the amount of assets and costs allocated thereto and justification for such allocations.

Response:

There are no non-utility assets or related costs to report for Until Energy Systems, Inc.

(19) Balance sheets and income statements for the previous 2 years if not previously filed with the commission.

Response:

This information is provided in the response to Puc 1604.01(a)(1).

(20) Quarterly income statements for the previous 2 years if not previously filed with the commission.

Response:

Please see PUC 1604.01(a) – 20 Attachment 1 for the quarterly income statements.

UNITIL ENERGY SYSTEMS, INC.
Quarterly Income Statement
G_UES_ISQ_Rate_Case

Schedule 3
2/19/2021
For Periods Ending December 31, 2020

	QTD March 2019	QTD June 2019	QTD September 2019	QTD December 2019	QTD March 2020	QTD June 2020	QTD September 2020	QTD December 2020
OPERATING REVENUES								
Electric Service Revenue:								
Residential (440)	$25,684,362.83	$19,502,368.61	$21,619,638.67	$18,747,755.17	$24,601,584.01	$20,834,035.61	$24,611,766.18	$19,614,933.35
General Service (442)	17,373,924.36	15,702,760.75	16,787,633.45	15,022,542.55	16,955,182.23	14,048,380.07	17,226,850.51	15,580,669.97
Public Street Light (444)	640,837.85	627,301.91	598,205.87	602,578.67	622,088.21	608,517.78	595,051.12	596,640.78
Sales to Public Auth (445)	611.86	2,684.10	3,865.94	2,331.18	1,281.07	1,618.49	2,443.20	2,202.07
Sales for Resale (447)	974,048.21	769,947.53	94,601.38	589,768.11	578,925.05	391,132.57	80,633.67	470,452.62
Other Sales (449)	(834,332.31)	(1,281,562.48)	1,833,806.37	4,339,481.38	(2,352,404.75)	(1,366,122.66)	(702,734.87)	3,823,453.96
Total Electric Service Revenue	43,839,452.80	35,323,500.42	40,937,751.68	39,304,457.06	40,406,655.82	34,517,561.86	41,814,009.81	40,088,352.75
Other Operating Revenues:								
Late Payment Charges (450)	55,867.35	94,400.51	70,878.38	54,391.16	94,676.12	(61.64)	(13.34)	(1.58)
Misc. Service Revenues (451)	35,926.13	86,559.37	88,532.86	69,959.26	41,079.10	51,705.00	52,463.00	49,748.68
Rent-elect. Property (454)	135,961.65	139,268.45	141,155.35	141,415.01	142,746.57	145,679.71	147,920.12	148,853.40
Other Electric Rev (456)	370,597.39	300,731.11	319,283.95	321,735.91	323,597.55	323,792.80	295,791.97	278,897.62
Total Other Operating Revenues	598,352.52	620,959.44	619,850.54	587,501.34	602,099.34	521,115.87	496,161.75	477,498.12
TOTAL OPERATING REVENUES	44,437,805.32	35,944,459.86	41,557,602.22	39,891,958.40	41,008,755.16	35,038,677.73	42,310,171.56	40,565,850.87
OPERATING EXPENSES								
Operation & Maint. Expenses:								
Purchased Power (555, 557)	21,696,716.81	13,220,814.62	14,239,863.44	16,213,488.97	18,371,287.42	10,131,948.79	11,774,850.22	12,727,434.31
Transmission (556, 560-579)	6,940,152.06	6,285,437.72	8,596,982.10	6,500,632.57	6,877,209.25	8,445,398.51	12,117,919.61	8,043,206.80
Distribution (580-599)	2,391,769.06	2,181,255.47	2,312,140.20	2,310,718.34	2,260,485.76	2,345,727.35	2,392,619.70	2,477,366.66
Cust. Accounting (901-905)	1,299,461.31	900,307.43	1,223,511.66	1,231,886.15	1,249,840.52	858,159.09	994,395.13	1,184,520.81
Cust. Service (907-910)	656,376.24	855,514.04	1,340,936.49	2,597,543.87	997,940.02	936,840.56	1,498,521.29	3,893,652.88
Admin. & General (920-935)	2,978,170.50	2,437,658.85	2,902,941.10	2,548,465.43	2,778,064.31	2,068,676.73	2,249,622.47	2,654,466.70
Total O & M Expenses	35,962,645.98	25,880,988.13	30,616,374.99	31,402,735.33	32,534,827.28	24,786,751.03	31,027,928.42	30,980,648.16
Other Operating Expenses:								
Deprtn. & Amort. (403-407)	4,072,684.01	3,630,873.81	3,779,353.17	3,801,050.85	3,936,111.67	3,938,010.76	4,022,361.86	4,046,734.95
Taxes-Other Than Inc. (408)	1,882,714.42	1,418,660.05	1,590,778.95	1,542,976.97	1,758,615.83	1,767,584.92	1,739,420.54	1,901,056.57
Federal Income Taxes (409)	737,588.22	(880,395.95)	3,748,272.33	1,066,646.33	1,084,668.72	(1,527,774.63)	268,463.57	(114,230.87)
State Income Tax (409)	101,619.47	(559,260.27)	1,556,240.01	608,749.60	338,510.47	301,598.01	49,938.25	(1,417,024.72)
Def. Income Taxes (410, 411)	(585,538.38)	2,365,708.53	(4,224,194.46)	(1,248,644.09)	(1,073,368.86)	2,075,490.50	833,164.73	2,107,002.27
Total Other Operating Expenses	6,209,067.74	5,975,586.17	6,450,450.00	5,770,779.66	6,044,537.83	6,554,909.56	6,913,348.95	6,523,538.20
TOTAL OPERATING EXPENSES	42,171,713.72	31,856,574.30	37,066,824.99	37,173,514.99	38,579,365.11	31,341,660.59	37,941,277.37	37,504,186.36
NET UTILITY OPERATING INCOME	2,266,091.60	4,087,885.56	4,490,777.23	2,718,443.41	2,429,390.05	3,697,017.14	4,368,894.19	3,061,664.51
OTHER INCOME & DEDUCTIONS								
Other Income:								
Other (419, 421)	107,983.60	93,391.32	108,854.88	94,677.33	103,691.74	93,883.13	90,589.48	82,476.87
Other Income Deduc. (425, 426)	59,306.00	65,146.11	40,743.41	60,790.53	70,000.24	110,592.88	38,231.25	53,749.58
Taxes Other than Income Taxes								
Income Tax, Other Inc & Ded (409)	13,260.26	7,694.28	18,554.25	8,948.40	9,124.67	(4,525.51)	14,180.19	7,780.21
Net Other Income & Deductions	35,417.34	20,550.93	49,557.22	24,938.40	24,566.83	(12,184.24)	38,178.04	20,947.08
GROSS INCOME	2,301,508.94	4,108,436.49	4,540,334.45	2,743,381.81	2,453,956.88	3,684,832.90	4,407,072.23	3,082,611.59
Interest Charges (427-432)	1,520,601.11	1,545,102.81	1,550,576.82	1,467,584.38	1,449,636.09	1,368,403.63	1,219,904.21	1,457,147.89
NET INCOME	780,907.83	2,563,333.68	2,989,757.63	1,275,797.43	1,004,320.79	2,316,429.27	3,187,168.02	1,625,463.70

(21) Quarterly sales volumes for the previous 2 years, itemized for residential and other classifications of service, if not previously filed with the commission.

Response:

Please see PUC 1604.01(a) – 21 Attachment 1 for the quarterly itemized sales volume.

Unitil Energy Systems, Inc.

MEGAWATT HOURS SOLD

Line No.	Title of Account (a)	Q4 2020 (b)	Q3 2020 (c)	Q2 2020 (d)	Q1 2020 (e)
1	Sales of Electricity				
2	(440) Residential Sales	111,950	156,067	114,839	133,113
3	(442) Commercial and Industrial Sales				
4	Small (or Commercial)	71,670	89,882	67,642	87,838
5	Large (or Industrial)	74,892	89,046	73,931	81,898
6	(444) Public Street and Highway Lighting	1,813	1,925	1,932	1,956
7	(445) Other Sales to Public Authorities	8	3	10	4
8	(446) Sales to Railroads and Railways	0	0	0	0
9	(448) Interdepartmental Sales	0	0	0	0
10	TOTAL Sales to Ultimate Consumers	260,333	336,923	258,354	304,809
11	(447) Sales for Resale	10,125	1,207	12,125	18,900
12	TOTAL Sales of Electricity	270,458	338,130	270,479	323,709
13	Sales of Electricity				

MEGAWATT HOURS SOLD

Line No.	Title of Account (a)	Q4 2019 (b)	Q3 2019 (c)	Q2 2019 (d)	Q1 2019 (e)
1	Sales of Electricity				
2	(440) Residential Sales	109,614	136,805	101,418	134,381
3	(442) Commercial and Industrial Sales				
4	Small (or Commercial)	77,711	94,960	79,906	88,134
5	Large (or Industrial)	78,829	89,974	78,663	79,367
6	(444) Public Street and Highway Lighting	1,969	1,974	1,991	1,994
7	(445) Other Sales to Public Authorities	13	5	8	1
8	(446) Sales to Railroads and Railways	0	0	0	0
9	(448) Interdepartmental Sales	0	0	0	0
10	TOTAL Sales to Ultimate Consumers	268,136	323,718	261,986	303,877
11	(447) Sales for Resale	12,459	1,071	21,173	18,560
12	TOTAL Sales of Electricity	280,595	324,789	283,159	322,437
13	Sales of Electricity				

***Information Per FERC Form 3Q (Quarterly) and FERC Form 1 (Annually)*

(22) A description of the utility's projected need for external capital for the 2 year period immediately following the test year.

Response:

Unitil Energy Systems, Inc. (“UES”) regularly reviews and analyzes its financing requirements. Over the next two years, UES does not have definitive permanent financing plans. UES will continue to monitor its need to raise long-term capital and request approval from the Commission if necessary.

For short-term debt financing, UES participates in Unitil Corporation’s Cash Pool to fund any cash shortfalls between long-term financings. The short-term borrowing limit is authorized by the Commission and is subject to annual adjustment.

(23) The utility's capital budget with a statement of the source and uses of funds for the 2 years immediately following the test year.

Response:

Please refer to the testimony of Mr. Kevin Sprague for the Company's capital budget and PUC 1604.01(a) 23 – Attachment 1 for the projected sources and uses of funds for calendar years 2021 and 2022.

PUC 1604.01(a) - 23 Attachment 1
Page 1 of 1

Unitil Energy Systems, Inc.
Sources and Uses of Funds for Years 2021 and 2022
Including the Projected Construction Budgets
($000's)

	2021 Forecast	2022 Forecast
Sources:		
NI	$ 7,919	$ 9,445
D&A	16,096	16,378
Change in DIT	1,023	1,459
Net Borrowings and Other	12,043	17,557
Total Uses	$ 37,081	$ 44,839
Uses:		
Capex	$ 27,906	$ 34,058
Dividends	5,675	5,781
Debt Retirements	3,500	5,000
Total Uses	$ 37,081	$ 44,839

(24) The amount of outstanding short-term debt, on a monthly basis during the test year, for each short-term indebtedness.

Response:

Please refer to PUC 1604.01(a) - 24 Attachment 1 for the month-end and average daily balance of short-term debt outstanding on a monthly basis during the test year.

Unitil Energy Systems, Inc.
Short-Term Debt Outstanding
12 Months Ended December 31, 2020

Line No.	Month	Month-End Amount Outstanding	Average Daily Borrowings
1	January 2020	$ 15,981,465	$ 13,423,371
2	February 2020	18,329,433	15,403,679
3	March 2020	25,006,584	22,479,815
4	April 2020	26,439,328	24,786,356
5	May 2020	26,575,577	25,292,157
6	June 2020	23,423,291	23,096,051
7	July 2020	26,686,489	25,491,071
8	August 2020	29,757,846	29,264,455
9	September 2020	4,767,278	17,205,102
10	October 2020	8,896,119	7,217,071
11	November 2020	6,996,466	6,214,346
12	December 2020	8,176,368	6,924,815

(25) If a utility is a subsidiary, a certificate of an appropriate official of the subsidiary detailing any expense of the parent company which was included in the subsidiary's cost of service.

Response:

Please see PUC 1604.01(a) - 25 Attachment 1 for the Certificate.

1604.01(a) – 25
Attachment 1
Page 1 of 1

Unitil
NH ELECTRIC OPERATIONS

Unitil Energy Systems, Inc.

Pursuant to the New Hampshire Code of Administrative Rules, Part 1604.01(a)(25), Unitil Energy Systems, Inc., hereby certifies the following:

No expense for the parent company (Unitil Corporation) is included in the cost of service for Unitil Energy Systems, Inc., as filed in this rate case.

Daniel J. Hurstak
Controller
Unitil Energy Systems, Inc.

State of New Hampshire
County of Rockingham, ss.

Signed and sworn this

3rd day of March, 2021

Notary Public

Sandra L. Whitney
NOTARY PUBLIC
State of New Hampshire
My Commission Expires January 22, 2025

(26) Support for figures appearing on written testimony and in accompanying exhibits.

Response:

Please refer to other volumes presented in this filing for support for figures appearing on written testimony and in accompanying exhibits.